STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

Docket No. 2001-507-E

In Re: Application of Palmetto Energy Center, LLC for Certificate of Environmental Compatibility and Public Convenience and Necessity to Construct a Major Utility Facility	DIRECT TESTIMONY OF WILLIAM GREGG JOCOY

Q. PLEASE STATE YOUR NAME AND ADDRESS

A. My name is Gregg Jocoy. My home address is 122 Spratt St., Fort Mill, SC 29715

Q. IN WHAT CAPACITY ARE YOU APPEARING TODAY?

A. I am a resident of Fort Mill living within 3 miles of the proposed Palmetto Energy Center LLC.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of myself.

Q. ARE YOU FAMILIAR WITH THE FACTS AND INFORMATION SET FORTH IN THE PALMETTO ENERGY'S APPLICATION?

A. Yes, I have reviewed the application and the supporting documents.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to oppose Palmetto Energy's Application for a Certificate of Environmental Compatibility and Public Convenience and Necessity to construct and operate a generating plant for the production of electric power and energy in York County, near Fort Mill, South Carolina ("Palmetto Energy Facility").

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE NEED FOR THE PROPOSED PALMETTO ENERGY FACILITY?

A. Upon review of the Application and supporting documents, I do not believe that a need has been established for this power plant.

1) The siting and regulation of wholesale electric utilities (i.e., merchant plants) has not been incorporated into the. South Carolina Code of Laws. While a mandate exists to provide fair market opportunities for these corporations, many issues are unresolved. According to James Blake Atkins, PhD, in Docket no. 2000-558-E-Order No. 2001-194 dated March 28, 2001: " Given the language of the current Utility Facility Siting and Environmental Protection Act, it is unclear how this Commission should assess the contribution(s) of merchant generation in serving system reliability. However, it is clear that South Carolina's current Utility Facility Siting and Environmental Protection Act empowers the commission with ensuring the construction of generation "serve system reliability", whether merchant or investor-owned. Additional guidance through rule making, or amendments to the current Act, is needed to resolve this question." [Exhibit 1 pg. 4]

2) Regulated electric suppliers in South Carolina are required to provide power in their assigned service areas and to prepare Integrated Resource Plans to ensure the energy supply will meet the projected demands. A review of the Integrated Resource Plans from SCE & G, Duke Power, and CP & L indicate that plans to purchase power from outside sources will be transient in nature; additional capacity of during peak usage is required, but this need was met with the approval of the Entergy plant. [Exhibit 1 pg. 3]

- Duke power indicates purchase contracts will peak in 2002, remain steady until 2003, and decline for the remainder of the projection period. They have stated their intent in their Integrated Resource plan "Duke expects to purchase approximately 82MW annually from other cogeneration and small power producers as identified in Appendix C. These firm purchases will decrease over time as contracts expire." [Exhibit 2]
- SCE&G indicates annual purchases of 100MW in 2001 and 2003 only and states "By maintaining a reserve margin in the 12 – 18% range as shown in the table, the Company addresses the uncertainties related to load and the availability of generation on the system as well as provides its share of support for the VACAR transmission grid." [Exhibit 3]
- CP&L indicates purchases of 1638MW in 2002 declining to 1600MW in 2007, then steadily declining for the remainder of the projection period. and states "Reliability assessments have shown that reserves projected in CP & L's RP are appropriate for providing an adequate and reliable power supply. Reserves are lower than historical levels due to a number of factors. Growth of the generating system and recent additions of smaller and highly reliable CT capacity increments to the company's resource mix decrease the level of reserves needed to maintain adequate reliability" [Exhibit 4]

In addition, there are a number of planned additions to SC in the near future by current energy providers [Exhibit 5 pp. 5 - 8]. The Palmetto Energy Center, LLC, if approved, is not projected to be online until 2005 at the earliest. By the time this plant comes online, the need to purchase wholesale power will be declining. The statement by Mr. Holland in his testimony (pg. 19, line 13) "Until someone, like Palmetto, commits to and actually builds these facilities, they cannot be relied upon to meet system needs." is presumptuous. Calpine has been a major player in the energy market for a relatively short period of time. Our current reliable providers, with many more years of successful energy experience than Calpine, have forecast their ability to meet our needs and planned accordingly.

3) The evidence is not clear as to whether unregulated wholesale facilities will reduce customer cost and ensure reliability. Palmetto Energy Center, LLC has used the argument that the "California Energy Crisis" should motivate us to proceed. Numerous Energy Professionals have come to different conclusions regarding the "California Energy Crisis", but Dr. Atkins states "the increasing market share of merchant plants can potentially result in increased price volatility to South Carolina's IOUs." [Exhibit 1, pg. 8]. It is public knowledge that the state of California is currently suing the unregulated plants, including Calpine for price fixing in time of need. The marketing strategies (e.g., contracts with other parties) of the Palmetto Energy Center may prevent South Carolina ratepayers from obtaining power at a prudent price in the event such power is needed. Many states, including South Carolina, are considering or have established moratoriums on Merchant Plant construction due to the unknown consequences of this development.

4) Another area of concern is the limited availability of prime sites for the construction of the more desirable natural gas plants [Exhibit 6]. The upstate of SC has the features of proximity of electric transmission lines, large natural gas lines, and a sufficient water supply. In the Palmetto Energy Center application, Calpine indicates that it was hard to find a suitable site, due to many factors. The siting of this plant may prevent the future siting of one dedicated to produce energy for the residents of this state, or will present financial obstacles relating the

high cost of extending gas lines and the power grid to another site.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ENIRONMENTAL COMPATIBILITY OF THE PROPOSED PALMETTO ENERGY FACILITY?

A. Upon review of the Application and supporting documents, I do not believe that the proposed Palmetto Energy Facility is compatible with the environment.

1) While York County is currently in attainment with the one-hour ozone standard, this information does not accurately reflect the ozone situation in Fort Mill.

a) The ozone monitor for York County [45091006-1] is in York, SC a rural area southwest of Fort Mill and southeast of York. The ozone monitor for Southwest Charlotte [371191005-1], near the state line, is in an area that is demographically more similar to the Fort Mill – Rock Hill area than is York. This monitor averages 1.6 exceedences of the 1-hour standard per year. Maps of the relative amount of criteria pollutants in SC counties are also included, as these pollutants contribute to ozone formation. [Exhibit 7]

b) South Carolina DHEC, in their document "Boundary Recommendations for South Carolina for the Remanded 8-hour ozone Standard", July 14, 2000, classifies Fort-Mill / Rock Hill as non-attainment if the 8-hour standard was enforced. This document states that 69% of the daily vehicle miles traveled within York County occur within the MPO boundary, 5 point sources in the MPO account for 99% of the 4,944.2 tons of NOx emitted annually from the whole county, and 6 point sources in the MPO emit 95% of the 3,227.1 tons of VOC emitted annually from the whole county. [Exhibit 8]

2) Formaldehyde is known to be a highly toxic compound which is considered by

Scorecard to have general (non-cancer) health risks from HAPS 2nd only to Acrolein in York County. DHEC air modeling requires no more than 15μg/m^3 at the plant perimeter, but overall formaldehyde levels are already quite high in York County (approx. 1μg/m^3 compared with an average ambient background of 0.25μ/m^3.). York County SC has the 63rd highest concentration of formaldehyde emissions from point sources in the United States, with approximately 52,870 lbs per year. Formaldehyde is a known emission from the combustion of natural gas, but data was not provided in the Calpine filing. A copy of data from the filing for the Wawayanda Energy Center (Calpine) in New York gives data for the GE 7FB turbines (same ones scheduled for Palmetto Energy Center) that would predict 13.6 tons per year for 3 turbines. This amount of formaldehyde would increase output from York County point sources from 52,870 lbs. to about 80, 070 lbs., moving the county from 63rd to 37th worst in the nation. It should be noted that, with catalytic oxidation, the amount of formaldehyde could be reduced to about 175 lbs. per year. While vehicles are a major source of formaldehyde pollution, contributions from point sources are significant, currently making up 13% of the total formaldehyde released in the county. Coupled with the DHEC statement that 95% of the VOCs in York County are emitted in the Fort Mill / Rock Hill MPO, the local situation is actually far worse than represented by the data. [Exhibit 9]

3) The emissions could be lowered from this plant but Calpine stated at the public forum in Fort Mill that they would build this plant to emit 3.5ppm NOx at the stack (SC standard) instead of meeting a more stringent 2.5ppm California standard. The representative repeatedly stated that Palmetto Energy Center would "meet the state and federal regulations", and no more. It is, however, possible to

achieve significantly lower emissions using better technology. Calpine committed to California that the East Altamonte Energy Center could meet emissions of 2.5 ppm NOx and 6.0 ppm CO vs. the 3.5 ppm NOx and 10 – 15ppm CO in their South Carolina application [Exhibit 10]. The state of Arizona recently required the Gila Bend combined cycle plant to meet California Emissions requirements, which are more stringent than the existing Arizona requirements [Exhibit 11]. Federal regulations are in development to reduce NOx emissions from power plants even more [Exhibit 12]. The South Carolina Public Service Commission can make permit decisions based, in part, on "environmental compatibility", but the DHEC permitting process must rely only on "environmental compliance" with current laws.

4) There is no statement or analysis of the amount of ammonia that will be released by the Palmetto Energy Center. The Altamonte Energy Center is projected to produce about 450 tons of ammonia annually but this is the amount Calpine committed to in the state of California, Palmetto Energy Center quantities may be greater. Of more concern is the anhydrous ammonia used in the catalytic reduction process. Anhydrous ammonia is very hazardous; leaks tend to stay towards the ground and drift downhill, and are lethal in high concentrations. Of particular concern is the lack of planning information for the containment and emergency response (the only response is rapid evacuation) on the limited access road leading from the plant area and serving other employers in the business park and considerations for residents and park visitors directly across the Catawba River. Alternate technologies using either aqueous ammonia or a new system using urea and on-site mixing would present safer options to the community. [Exhibit 18]

5) This plant will not be linked to the decommissioning of a coal plant. Local representatives were under the impression that this plant would "clean the air"; this is only the case if commissioning the natural gas plant is linked to the decommissioning of a coal plant. The nearest South Carolina coal plant is in Columbia.

6) The water purification system (filtration, multimedia, and demineralization) for the boiler make-up is not designed to remove volatile organic compounds which will distill from the boiler into the air due to their lower boiling point than water; the Celanese plant discharges approximately 6 tons per year of volatile organic chemicals [Exhibit 13] upstream of the planned intake for the boiler. In addition, organic compounds are released into the river by storm drain runoff. The potential significance of this impact is unknown at this time.

7) The environmental impact study presented by CH2M Hill presented in the initial application is incomplete, as it does not discuss potential environmental impact on threatened on endangered species not directly on the site.

In conclusion, the Palmetto Energy Center, classified as a major source of emissions requiring a Title V permit, will have a major environmental impact, which Calpine claims will be proven as "insignificant". Court Cases in California have ruled the ratio analysis theory (a large amount of pollution in a polluted area is insignificant because its percentage contribution to total pollution is small) to be flawed and have ruled that "the more severe existing environmental problems are, the lower the threshold should be for treating a project's cumulative impacts as significant" [Exhibit 14]

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE PUBLIC CONVENIENCE OF THE PROPOSED PALMETTO ENERGY FACILITY?

A. Upon review of the Application and supporting documents, I do not believe that the proposed Palmetto Energy Facility provides for the public convenience.

1) The description of the rationale for choosing the Fort Mill site over the Newport site is misleading. In the application for the Palmetto Energy Center, Calpine makes the following statement concerning the Newport location: "While these sites were zoned industrial, they were in areas that have become or are rapidly becoming residential, and the use was viewed as incompatible with the surrounding neighborhoods." The Fort-Mill / Rock Hill MSA is, in fact, the part of the county experiencing the most rapid growth. The recent widening of I-77 and plans for a Southern-Bypass around Fort Mill can only add to this growth. A Map of the county and the "General Plan" showing growth projections for York County are provided as supporting evidence [Exhibit 15].

2) This project may have a detrimental impact on property values in the area. Calpine has not presented evidence (other than a handful of anecdotal quotes) to demonstrate that property values do not decrease. While it is possible to rebut these quotes with equivalent anecdotal stories, the bottom line is that a legitimate analysis, by an uninterested 3rd party source should be performed. In addition, current land use planning in the Fort Mill Township places land zoned for residential development directly adjacent to the proposed Palmetto Energy Center site [Exhibit 16]. It should be noted that, in their own application, Calpine expressed concern about locating their facility in areas that are rapidly becoming residential, supporting the argument that property values may be impacted. A loss of property values will result in an offsetting loss of tax revenue.

3) The historic and archaeological study reports that the "Red River District is of historic and archaeological significance. An observation of the consultant, TRC is that "The area generally has a high probability for archaeological sites, as

demonstrated by surveys in the vicinity of the project tract. It is likely that the SC SHPO will require and archaeological survey of the project area", and "The SC SHPO may also request that potential visual impacts for the project be assessed." No mention was made of the Catawba River Corridor Planning Project, which focuses on the 30 mile segment of the river below the Lake Wylie Dam to the Fishing Creek Reservoir. Neither was mention made of River Park, a 70 acre park across the river slightly downstream from the proposed site (the proposed site is clearly visible from the northern terminus of the park). [Exhibit 17]. This stretch of the river is scenic and it is hard to imagine that a facility as large as the proposed Palmetto Energy Center, perched about 80 feet above the riverbed will not be a blight on the landscape when viewed from this protected area.

4) The tax benefits may be greatly offset by the use of tax money and ratepayer (i.e., natural gas prices, and electric prices) to provide the tax incentives and infrastructure to support this project. In any event, while Fort Mill always needs more money for the school system, and the FILO money will provide these resources, the use of such funds will spread the cost of this project across residents in the poorer counties of South Carolina. Mr. Nyland's testimony "neither the State of South Carolina nor any of the residents of the State will be responsible for any of the costs of the project." is misleading. Tax breaks to Palmetto Energy Center come from taxes paid by residents of South Carolina. The negotiations for the cost of the pipeline enhancements is still sketchy [Exhibit 19].

5) There has been no impact analysis concerning the burdens this facility will place on the community's infrastructure during construction (i.e., crime, short-term housing, influx of more children into the school system short-term, police and fire

protection, protection from terrorist acts, etc.).

6) Because Palmetto Energy Center LLC is a limited liability corporation, the cost of a catastrophic event causing more damage than the Palmetto Energy Center could mitigate would be borne by South Carolina taxpayers instead of Calpine, the Parent Corporation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

EXHIBIT 1

South Carolina Public Service Commission
Docket No. 2000-558E-Order No. 2001-194, March 28, 2001 pp. 23-31

3. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Chairman

ATTEST:

Executive Director

(SEAL)

Concurring Opinion of Commissioner James Blake Atkins, Ph.D.

It is important to note that the Greenville Generating Facility is the first merchant facility proposed and certificated in South Carolina. In my opinion, the treatment and evaluation of this Application presented numerous problems, to both the Commission Staff as well as Commissioners. In previous siting cases, the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. Section 58-33-10, et seq. (1976 and Supp. 2000), has always been applied to the siting of generation and transmission by investor-owned utilities (IOUs), or either the construction of generation by independent power producers under contract to the State' s IOUs. The certification of this facility represents the beginning of the transition to a wholesale generation market in South Carolina, and with the continued implementation of [transmission] open access and regional transmission organizations (RTOs), can have a profound impact on the future of the existing vertically integrated electric market in our state. The significance of the Greenville Generating Facility decision on siting matters and the future wholesale and retail evolution of electricity markets in South Carolina should not be minimized.

Despite the unanimous vote in this matter, many of the issues raised during the hearing remain unresolved and problematic. The majority of the issues discussed in the hearing are contained in the North American Electric Reliability Council's Report, Reliability Assessment 2000-2009, The Reliability of Bulk Electric Systems in North America, October 2000 (hereinafter referred to as "NERC Report"). (Hearing Exhibit 2). This document is referenced extensively throughout this opinion. This opinion focuses on the conflicting issues faced by this Commission in siting merchant generation, compared with siting a traditional IOU facility, under the existing Utility Facility Siting and Environmental Protection Act. This matter was further complicated by the fact that the Commission has never promulgated substantive regulations to administer this Act, which was signed into law in 1971. Further, it should be noted that these issues are not unique to South Carolina, and will continue to be debated and discussed throughout the Nation. The ongoing controversy in California over power shortages, soaring wholesale costs, and retail rate caps is evidence that the evolution of wholesale markets remains incomplete.

In voting with the majority in this matter, I concur that the proposed 900 MW Greenville Generating Facility has the potential to provide additional reserve peak undesignated generation for the region. The need for such undesignated generation has been clearly set forth in the Integrated Resource Plans (IRPs) submitted to the Commission by South Carolina Electric and Gas Company, Carolina Power and Light and Duke Energy. Because of the size of this facility, it has the potential to meet all of the estimated undesignated generation [purchases] for our investor-owned utilities (IOUs) beyond the Year 2009. This undesignated purchase amount does not include generation additions set forth by the IOUs in their respective IRPs. Ultimately, the portfolio of short or long-term futures contracts with our IOUs will determine whether or not the Greenville Generating Facility serves South Carolina' s system economy and reliability in the future.

Discussion

The electric industry in the United States is in the midst of a major transition from vertically integrated electric utilities to a competitive marketplace for generation at the wholesale level. The Energy Policy Act of 1992 expanded the ability of non-utility companies to build and operate power plants to foster the development of wholesale generation markets. In 1996, the Federal Energy Regulatory Commission (FERC) issued Orders 888 and 889 to allow these competitive generators open [non-discriminatory] access to bulk transmission systems. Recently, FERC Order 2000 established a framework for regional transmission organizations (RTOs) to improve the engineering and economic efficiency and operation of the transmission system. (NERC Report at 32).

To avoid the failings of other deregulation and re-regulation attempts in other states, this Commission must address many important and challenging implementation issues. Rapid changes in the wholesale market will bring many challenges to the market participants as they react to economic pressures while simultaneously attempting to maintain the reliability of the power system. (Id.).

The role of state commissions, under their traditional role of siting, IRPs review and fuel case adjudication is being modified as the industry restructures. This is true even in states such as South Carolina, where retail deregulation has not occurred. Given the language of the current Utility Facility Siting and Environmental Protection Act, it is unclear how this Commission should assess the contribution(s) of merchant generation in serving system reliability. However, it is clear that South Carolina's current Utility Facility Siting and Environmental Protection Act empowers the Commission with ensuring that the construction of generation "serve system reliability", whether merchant or investor-owned. Additional guidance through rule making, or amendments to the current Act, is needed to resolve this question.

As the electric industry restructures, wholesale generation developers are primarily driven by financial incentives, and not the maintenance of resource planning margins. (NERC Report at 9). This is a vast departure from the traditional integrated resource planning conducted by our IOUs since 1992. This raises the question as to how much generation capacity is adequate, and to what extent the Commission should be involved. Future decisions in the emerging wholesale market, regarding generation additions, will be based on short construction lead-times, and will be influenced by competitive considerations. Therefore, in administering the Utility Facility Siting and Environmental Protection Act and integrated resource planning, how should the Commission address the contribution of merchant plants to "system reliability?" If a merchant plant exists, will it actually add to generation reliability? No such system reliability question exists regarding the contribution from generation owned by independent power producers with long-term contracts for power sales to our IOUs.

Another important reliability issue concerns the actual location of merchant generation in relationship to transmission. The location of future generating facilities will play an important role in the delivery of merchant power to end-users, especially in light of congested transmission paths. (NERC Report at 17). In terms of transmission adequacy and security, procedures to mitigate potential negative reliability impacts function effectively today. However, future transmission loadings will increase as new loading patterns emerge resulting from increased power transfers brought on by the growth in wholesale generation. (NERC Report at 29).

The urgency of transmission planning to address congestion is clearly stated within the discussion of the Southeastern Reliability Council's (SERC) transmission assessment. (NERC Report at 67). The assessment states that:

> The ability to transfer power above contractually committed uses both intra- and inter-regionally, has become marginal on some interfaces under both studied and actual operating conditions. The increase in bulk power marketing activity resulting from transmission open access tariffs continues to push the operating state of the transmission system into conditions for which it was not originally planned. SERC member systems need to take a proactive role in advocating the continued planning and operation of the system in a manner that meets NERC and SERC reliability criteria.

The challenge of this Commission during the transition to a wholesale market is to enable market participants to build (site) transmission and generation projects in optimal locations (from both a transmission and generation perspective) to obtain the maximum benefits of competition while maintaining reliability. (NERC Report at 32). However, because of the competitive forces at work in wholesale generation, optimal siting of both generation and transmission concurrently may never function as efficiently as a vertically integrated system. This then raises the important issue that was never addressed during this hearing. In an effort to continue to promote system reliability within our current regulated market, should a series of alternative sites be considered (under the Act) which provides for "optimal" generation and transmission siting? An alternative siting analysis was clearly envisioned as a component of the Act (Section 58-33-160, (2)). Without such, it would appear that transmission congestion may be increased resulting in "non-optimal" transmission investments by RTOs.

In the future, the Commission's current siting authority, and new planning and implementation responsibilities of the RTO must be made consistent or merged. With the increasing [future] dependence on merchant generation, capacity siting will not necessarily be driven by load forecasting by our IOUs, but by market price signals. While price signals are important, there will continue to be a need to forecast trends and conditions within regions for the developer within their process. It will also continue to be important to forecast, and balance, both the location of the loads and the supply so that reliability is balanced. Ultimately, what entity (state commissions, RTOs, NERC or FERC) will be responsible for oversight of this forecasting? Will these new arrangements replace integrated resource planning in South Carolina despite the fact that we have a vertically integrated, regulated market?

NERC raises a number of these same concerns (NERC Report at 35):

> In a market environment, load forecasting will become a more challenging function for the industry. NERC's Load Forecasting Working Group may have to address these forecasting issues to insure that forecasts are totally representative of the needs of the regions. Who will ultimately be responsible for the quality of the load forecast given that multiple parties are involved in the development of the forecast of demand, supply, and the resulting market signals? How will the load forecast be communicated, and how can it be challenged?

Another extremely important issue that was not addressed by Commission Staff during the hearing concerns system reactive power. Maintenance of system reactive power is critical to the maintenance of voltage stability within the transmission system. When power transfers follow consistent directional patterns, planning for reactive power is straightforward. Under open access, transactions are being conducted over greater distances, and in directions and amounts that were not anticipated when the current transmission system was constructed. These power transfers are volatile, changing both daily and hourly, and make planning for reactive power enhancements difficult. With the implementation of the wholesale generation market, disincentives have been created which reduce reactive power generation. Because of the "economic incentive" to produce more real power by the wholesale generators, reactive power has been eroded since reactive power decreases as real power output increases. It will be critical that under FERC Order 2000, and the resultant implementation of the RTOs, that the load serving and transfer capability of the bulk transmission system be increased, including an analysis of the siting of merchant plants on maintenance of system reactive capability. (NERC Report at 30). Because the applicant failed to file any transmission interconnection studies as part of this application, this Commission has no knowledge of the implications of this facility on reactive power. Future applications and associated testimony must address these issues in the Commission hearing, so as to insure system reliability as required in the Act.

As previously mentioned, the portfolio of contracts between our IOUs and the Greenville Generating Facility can have an important impact regarding the price paid for the power from this facility. Because power from this facility can be moved along the 500kv transmission line to which the plant will be interconnected, power will be easily available for sale to other regions outside of VACAR and SERC. This can have a profound impact on the market price as described by NERC. (NERC Report at 33):

> In contrast to the stable energy prices of the traditional regulated utility with an obligation to serve the demand of its native load, the provision of electric energy in an open market environment will reflect the potentially volatile prices in the commercial market. As price spikes have indicated in the past, the market price in the short term may become excessively high. These high prices may result in situations where providers, unsure of recovery of costs, curtail services to customers, or consumers will no longer be able to afford the service. In an absence of an obligation to serve, high market prices may jeopardize continuity of electric service in the sense that unaffordable prices may discourage providers from purchasing and providing energy to consumers.

Although this is the California scenario and unlikely in the Southeast, <u>the increasing market share of merchant plants can potentially result in increased price volatility to South Carolina' s IOUs. Without existing futures contracts, our IOUs may have to purchase peak power during volatile periods, which will reflect the open market price in other regions, and not necessarily the lower "avoided</u>

cost" which has been observed previously. Depending upon the marketing of power from a merchant plant during peak periods, power may not be available for purchase by our IOU resulting from spot market and short-term contracts with other parties from the merchant plant. This Commission needs to devote additional attention to the availability of power from merchant plants during such peak periods, and ensure that the available power reflects a "prudent" price for our wholesale and retail consumers.

James Blake Atkins, Ph.D.

EXHIBIT 2

The Duke Power Annual Plan, September 1, 2001
pp. 11, 12, & 28

THE DUKE POWER ANNUAL PLAN
SEPTEMBER 1, 2001

Seasonal Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2001 Annual Plan Base Case

W = WINTER, S = SUMMER	W	S	W	S	W	S	W	S	W	S	W	S	W	S	
	01/02	2002	02/03	2003	03/04	2004	04/05	2005	05/06	2006	06/07	2007	07/08	2008	(
orecast															
1 Duke System Peak	16,474	18,504	16,750	18,872	17,028	19,238	17,309	19,610	17,460	19,842	17,726	20,204	18,002	20,573	1
umulative System Capacity															
2 Generating Capacity	19,350	19,350	19,350	19,350	19,960	19,960	19,960	19,960	19,960	19,960	19,764	19,644	19,644	19,644	1
3 Capacity Additions				610											
4 Capacity Retirements	0	0	0	0	0	0	0	0	0	(196)	(120)	0	0	0	
5 Cumulative Generating Capacity	19,350	19,350	19,350	19,960	19,960	19,960	19,960	19,960	19,960	19,764	19,644	19,644	19,644	19,644	1
6 Cumulative Purchase Contracts	993	1,144	1,144	1,144	492	492	492	482	272	272	272	121	121	121	
7 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8 Cumulative Future Resource Additions				(-175)											
Peaking/Intermediate	0	275	0	100	0	1,170	0	1,640	0	2,320	680	3,126	1,486	3,450	
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Cumulative Production Capacity	20,343	20,769	20,494	21,204	20,452	21,622	20,452	22,082	20,232	22,356	20,596	22,891	21,251	23,215	2
eserves w/o DSM															
10 Generating Reserves	3,869	2,265	3,744	2,332	3,424	2,384	3,143	2,472	2,772	2,514	2,870	2,687	3,249	2,642	
11 % Reserve Margin	23.5%	12.2%	22.4%	12.4%	20.1%	12.4%	18.2%	12.6%	15.9%	12.7%	16.2%	13.3%	18.0%	12.8%	
12 % Capacity Margin	19.0%	10.9%	18.3%	11.0%	16.7%	11.0%	15.4%	11.2%	13.7%	11.2%	13.9%	11.7%	15.3%	11.4%	
SM															
13 Cumulative DSM Capacity	470	888	468	890	466	890	465	869	464	861	463	853	462	846	
14 Cumulative Equivalent Capacity	20,813	21,657	20,962	22,094	20,918	22,512	20,917	22,951	20,696	23,217	21,059	23,744	21,713	24,061	2
eserves w/DSM															
15 Equivalent Reserves	4,339	3,153	4,212	3,222	3,890	3,274	3,608	3,341	3,236	3,375	3,333	3,540	3,711	3,488	
16 % Reserve Margin	26.3%	17.0%	25.1%	17.1%	22.8%	17.0%	20.8%	17.0%	18.5%	17.0%	18.8%	17.5%	20.6%	17.0%	
17 % Capacity Margin	20.8%	14.6%	20.1%	14.6%	18.6%	14.5%	17.2%	14.6%	15.6%	14.5%	15.8%	14.9%	17.1%	14.5%	

Seasonal Projections of Load, Capacity, and Reserves
for Duke Power and Nantahala Power and Light
2001 Annual Plan Base Case

W = WINTER, S = SUMMER	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	2009	09/10	2010	10/11	2011	11/12	2012	12/13	2013	13/14	2014	14/15	2015	15/16	201
recast															
1 Duke System Peak	20,946	18,528	21,318	18,794	21,688	19,063	22,056	19,319	22,425	19,573	22,780	19,829	23,143	20,094	23,5
ımulative System Capacity															
2 Generating Capacity	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,3
3 Capacity Additions															
4 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Cumulative Generating Capacity	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,376	19,3
6 Cumulative Purchase Contracts	121	121	121	121	121	121	121	121	121	33	33	33	33	33	
7 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8 Cumulative Future Resource Additions															
Peaking/Intermediate	4,256	2,616	4,742	3,102	5,066	3,426	5,548	3,908	6,030	4,390	6,516	4,876	6,998	5,358	7,
Base Load	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
9 Cumulative Production Capacity	23,753	22,113	24,239	22,599	24,563	22,923	25,045	23,405	25,527	23,799	25,925	24,285	26,407	24,767	26,
əserves w/o DSM															
10 Generating Reserves	2,807	3,585	2,921	3,805	2,875	3,860	2,989	4,087	3,102	4,226	3,145	4,457	3,264	4,673	3,
11 % Reserve Margin	13.4%	19.4%	13.7%	20.2%	13.3%	20.3%	13.6%	21.2%	13.8%	21.6%	13.8%	22.5%	14.1%	23.3%	1
12 % Capacity Margin	11.8%	16.2%	12.1%	16.8%	11.7%	16.8%	11.9%	17.5%	12.2%	17.8%	12.1%	18.4%	12.4%	18.9%	1
SM															
13 Cumulative DSM Capacity	839	460	833	460	826	459	820	459	814	459	808	459	803	460	
14 Cumulative Equivalent Capacity	24,592	22,573	25,072	23,059	25,389	23,382	25,865	23,864	26,341	24,258	26,733	24,744	27,210	25,227	27,
eserves w/DSM															
15 Equivalent Reserves	3,646	4,045	3,754	4,265	3,701	4,319	3,809	4,546	3,916	4,685	3,953	4,916	4,067	5,133	4
16 % Reserve Margin	17.4%	21.8%	17.6%	22.7%	17.1%	22.7%	17.3%	23.5%	17.5%	23.9%	17.4%	24.8%	17.6%	25.5%	1
17 % Capacity Margin	14.8%	17.9%	15.0%	18.5%	14.6%	18.5%	14.7%	19.0%	14.9%	19.3%	14.8%	19.9%	14.9%	20.3%	1

1. Rockingham L.L.C. has constructed a gas-fired, five-unit, 750 MW generation facility in Rockingham County, NC. Duke Power has a contract to purchase 600 MW of capacity and energy generated by the power plant. The contract term began July 1, 2000 and runs through the end of 2003.

2. Duke Power has entered into a contract to purchase 151 MW for the period June 1, 2001 to December 31, 2005 from the CP&L Rowan County North Carolina Plant Unit 2. Duke Power entered into a contract to purchase 151 MW for the period June 1, 2002 to May 31, 2007 from the CP&L Rowan County North Carolina Plant Unit 1.

3. Duke purchases 88 MW of capacity from Cherokee Cogeneration on an annual basis, through June 2013.

4. Duke expects to purchase approximately 82 MW annually from other cogeneration and small power producers as identified in Appendix C. These firm purchases will decrease over time as contracts expire.

EXHIBIT 3

2001 Integrated Resource Plan SCE & G
pp. 7 & summer load forecast

2001

Integrated

Resource

Plan

SCE&G®
A SCANA COMPANY

this weather contingency. To address the forecast error, we add another 50 megawatts to the demand reserve for a total of 150. Thus a reasonable range for the demand reserves is 100 to 150 megawatts.

By maintaining a reserve margin in the 12% – 18% range as shown in the table, the Company addresses the uncertainties related to load and to the availability of generation on its system as well as provides its share of support for the VACAR transmission grid. SCE&G will monitor its reserve margin policy in light of the changing power markets and its system needs and will make changes to the policy as warranted.

Projected Loads And Resources

The table on the following page shows SCE&G's projected loads and resources for the next 15 years. Known capacity additions include: the Urquhart Re-powering project in 2002, the uprate at Fairfield Pumped Storage Facility in 2003 and 2004 and a combined cycle plant in 2004. The Company's total firm load obligation includes a firm contract sale for the years 2004 through 2012. The Company believes that this supply plan will be as benign to the environment as possible because of its reliance on efficient, gas fired generation and that it will keep the cost of energy service competitive since the generating units being added are competitive with other units being added in the market.

SCE&G Forecast of Summer Loads and Resources

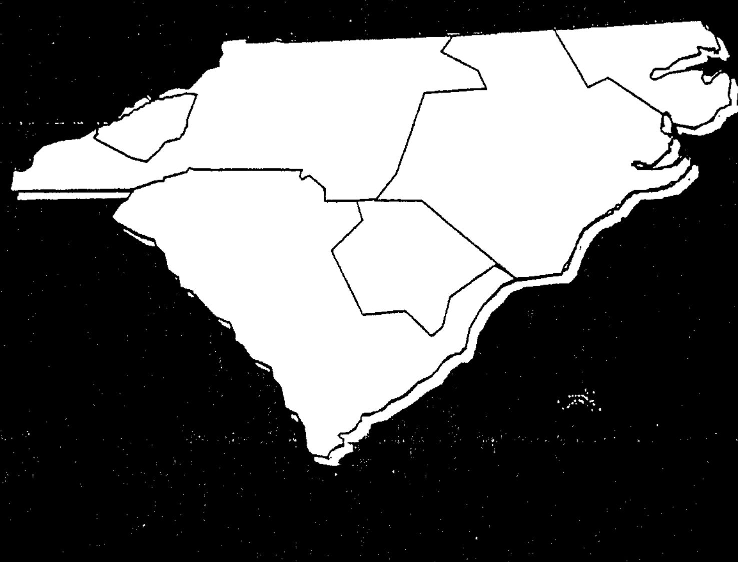
YEAR	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ecast														
Gross Territorial Peak	4471	4626	4709	4797	4894	4993	5078	5158	5243	5332	5404	5477	5574	5681
Less: DSM	282	282	282	282	282	282	282	282	282	282	282	282	282	282
Net Territorial Peak	4189	4344	4427	4515	4612	4711	4796	4876	4961	5050	5122	5195	5292	5399
Firm Contract Sales				250	250	250	250	250	250	250	250	250		
Total Firm Obligation	4189	4344	4427	4765	4862	4961	5046	5126	5211	5300	5372	5445	5292	5399
apacity														
Existing	4588	4588	4938	4962	5861	5861	5861	5861	5861	6011	6161	6161	6161	6161
Additions														
Urquhart Re-Powering		350												
Fairfield P.S.			24	24										
Combined Cycle CT				875										
Undecided									150	150				
Total System Capacity	4588	4938	4962	5861	5861	5861	5861	5861	6011	6161	6161	6161	6161	6161
Firm Annual Purchase	100		100											
Total Production Capability	4688	4938	5062	5861	5861	5861	5861	5861	6011	6161	6161	6161	6161	6161
With DSM Impact														
Margin	499	594	635	1096	999	900	815	735	800	861	789	716	869	762
% Reserve Margin	11.9%	13.7%	14.3%	23.0%	20.5%	18.1%	16.2%	14.3%	15.4%	16.2%	14.7%	13.1%	16.4%	14.1%
% Capacity Margin	10.6%	12.0%	12.5%	18.7%	17.0%	15.4%	13.9%	12.5%	13.3%	14.0%	12.8%	11.6%	14.1%	12.4%
Without DSM Impact														
Margin	217	312	353	814	717	618	533	453	518	579	507	434	587	480
% Reserve Margin	4.9%	6.7%	7.5%	16.1%	13.9%	11.8%	10.0%	8.4%	9.4%	10.4%	9.0%	7.6%	10.5%	8.4%
% Capacity Margin	4.6%	6.3%	7.0%	13.9%	12.2%	10.5%	9.1%	7.7%	8.6%	9.4%	8.2%	7.0%	9.5%	7.8%

EXHIBIT 4

CP & L Resource Plan, June 31, 2001
pp. 8 & Appendix B (summer)

CP&L
A Progress Energy [illegible]

Resource Plan



South Carolina Public Service Commission
Docket No. 2001-265-E
June 30, 2001

and coal facilities, will continue to provide reliable and cost-effective generation to serve customer energy needs.

Effect of plan on reliability of energy service

The reliability of energy service is a primary input in the development of the RP. This Plan provides for a reliable supply of electricity.

Carolina Power & Light Company employs both deterministic and probabilistic reliability criteria in the resource planning process. The Company establishes a reserve criterion for planning purposes based on probabilistic assessments of generation reliability, industry practice, historical operating experience, and judgement. Probabilistic assessments are significant because they capture the random nature of system behavior such as generator equipment failures and load variation.

CP&L conducts multi-area probabilistic analyses to assess generation system reliability. A multi-area analysis takes into consideration the capacity assistance available through interconnections with neighboring electric utilities. Decision analysis techniques are also incorporated in the analysis to capture load uncertainty. Generating reliability depends on the strength of the interconnections, the generation reserves available from the neighboring systems, and also the diversity in loads throughout the interconnected area. Thus, the interconnected system analysis shows the overall level of generation reliability and reflects the expected risk of capacity deficient conditions for supplying load.

A Loss-of-Load Expectation (LOLE) of one day in 10 years is a widely accepted criterion for establishing system reliability. CP&L uses a target reliability of one day in ten years LOLE for generation reliability assessments. LOLE can be viewed as the expected number of days that the load will exceed available capacity. Thus, LOLE indicates the number of days that a capacity deficient condition would occur, resulting in the inability to supply customer demand. Results of the probabilistic assessments are correlated to appropriate deterministic measures such as capacity margin or megawatt reserve for use in developing the resource plan.

Reliability assessments have shown that reserves projected in CP&L's RP are appropriate for providing an adequate and reliable power supply. Reserves are lower than historical levels due to a number of factors. Growth of the generating system and recent additions of smaller and highly reliable CT capacity increments to the company's resource mix decrease the level of reserves needed to maintain adequate reliability. Performance of CP&L's existing nuclear and fossil fleet has greatly improved over the past few years, which has also significantly contributed to improved system reliability. Finally, shorter construction lead times for building new power plants allows greater flexibility to respond to changes in capacity needs and thus reduces exposure to load uncertainty.

CAROLINA POWER & LIGHT CO.
June 2001 RESOURCE PLAN (Summer)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
GENERATION ADDITIONS																
Rowan Co. CT	456															
Richmond Co. CT	620	465	155													
Richmond Co. ST		160	160	160												
Harris NP Uprate		40														
Brunswick NP Uprate			50	50	43	43										
Undesignated Capacity (1)					155		155	310	310	465	310	310	310	310	310	310
INSTALLED GENERATION																
Combustion Turbine	3,276	3,431	3,276	2,966	2,966	2,966	2,966	2,966	2,966	2,966	2,966	2,966	2,966	2,966	2,966	2,966
Combined Cycle	84	554	1,024	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494	1,494
Hydro	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218
Fossil Steam	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285	5,285
Nuclear	3,174	3,214	3,264	3,314	3,357	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400	3,400
Undesignated Capacity (1)	-	-	-	-	155	155	310	620	930	1,395	1,705	2,015	2,325	2,635	2,945	3,255
PURCHASES & OTHER RESOURCES																
SEPA	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG Renewable	70	68	67	67	67	22	22	22	15	6	6	6	5	5	3	3
NUG Cogeneration	263	231	68	68	68	68	-	-	-	-	-	-	-	-	-	-
Fayetteville	283	283	283	283	283	283	283	283	283	283	283	283	283	283	283	283
AEP/Rockport 2	250	250	250	250	250	250	250	250	250							
PECO Purchase (2)	300	300	300													
Broad River CT	643	794	794	794	794	794	794	794	794	794	794	794	794	794	794	794
Seasonal Purchase	170															
TOTAL SUPPLY RESOURCES	14,126	14,737	14,938	14,848	15,046	15,044	15,131	15,441	15,744	15,950	16,260	16,570	16,879	17,189	17,497	17,807
UNIT POWER SALES	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456	456
NET RESOURCES FOR LOAD	13,670	14,281	14,482	14,392	14,590	14,588	14,675	14,985	15,288	15,494	15,804	16,114	16,423	16,733	17,041	17,351
PEAK DEMAND																
CP&L Retail	8,222	8,466	8,699	8,915	9,136	9,346	9,563	9,768	9,976	10,181	10,384	10,598	10,809	11,013	11,221	11,420
CP&L Wholesale	3,038	3,073	3,000	3,047	3,103	3,157	3,212	3,262	3,324	3,382	3,442	3,498	3,566	3,630	3,695	3,757
SYSTEM PEAK LOAD	11,260	11,539	11,699	11,962	12,240	12,503	12,775	13,030	13,300	13,563	13,826	14,096	14,376	14,643	14,916	15,177
Fayetteville Replacement	180	210	230	230	230	230	230	230	230	230	230	230	230	230	230	230
Firm Contract Sales	760	750	750	550	550	100	-	-	-	-	-	-	-	-	-	-
FIRM OBLIGATIONS	12,200	12,499	12,679	12,742	13,020	12,833	13,005	13,260	13,530	13,793	14,056	14,326	14,606	14,873	15,146	15,407
Large Load Curtailment	328	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322
Voltage Reduction	49	50	52	53	54	56	57	59	60	61	63	64	65	66	68	69
TOTAL LOAD	12,577	12,871	13,053	13,117	13,396	13,211	13,384	13,640	13,911	14,176	14,440	14,712	14,993	15,261	15,535	15,798
RESERVES (3)	1,470	1,782	1,803	1,650	1,571	1,755	1,670	1,726	1,758	1,701	1,748	1,787	1,817	1,860	1,895	1,944
CAPACITY MARGIN (4)	10.8%	12.5%	12.5%	11.5%	10.8%	12.0%	11.4%	11.5%	11.5%	11.0%	11.1%	11.1%	11.1%	11.1%	11.1%	11.2%
RESERVE MARGIN (5)	12.1%	14.3%	14.2%	13.0%	12.1%	13.7%	12.8%	13.0%	13.0%	12.3%	12.4%	12.5%	12.4%	12.5%	12.5%	12.6%

NOTES:

1) For planning purposes only; does not indicate a commitment to type, amount or ownership.
2) For the months of June through September.
3) Reserves = Net Resources For Load - Firm Obligations
4) Capacity Margin = Reserves / Net Resources For Load * 100.
5) Reserve Margin = Reserves / Firm Obligations * 100.

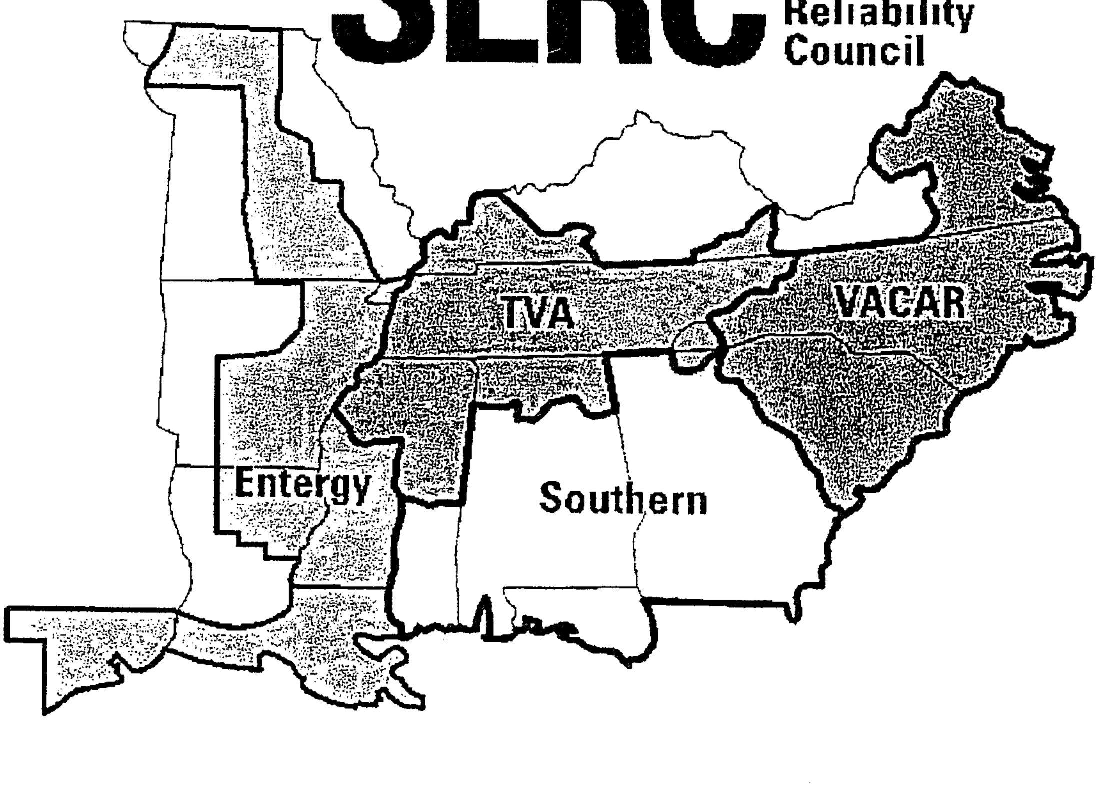
EXHIBIT 5

Southeastern Reliability Council Regional Electricity Supply & Demand Projections EIA-411, 2001-2010, June 15, 2001. Cover to TOC and Section 3.4, VACAR Subregion

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

REGIONAL ELECTRICITY SUPPLY & DEMAND PROJECTIONS
(EIA-411)

SERC Southeastern Electric Reliability Council



2001-2010 **June 15, 2001**

June 15, 2001

Mr. Brian M. Nolan
North American Electric Reliability Council
Princeton Forrestal Village
116-390 Village Boulevard
Princeton, NJ 08540-5731

Dear Brian:

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
REGIONAL ELECTRICITY SUPPLY & DEMAND PROJECTIONS (EIA-411)
2001-2010

Enclosed is a copy of the Southeastern Electric Reliability Council (SERC) report, "Regional Electricity Supply & Demand Projections" for the period 2001-2010. This data has been provided by member systems of the Southeast Region. Two copies are being mailed to each of the affected State Public Service Commissions. It is our understanding that NERC will provide Department of Energy organizational units appropriate copies of this data.

Any questions about this document should be addressed to:

James N. Maughn, Administrative Manager
Southeastern Electric Reliability Council
P. O. Box 2641 12N-8250
Birmingham, AL 35291
Telephone: (205) 257-6361

Sincerely,

James N. Maughn
Administrative Manager SERC

enclosure

June 2001

INTRODUCTION

The Southeastern Electric Reliability Council (SERC) continues to observe guidelines in keeping with the goals and objectives stated in the SERC organizational agreement. These guidelines include (1) reporting load forecasts based on a uniform 60-minute integrated net peak demand under average weather conditions, (2) rating of generating units on a uniform-test basis of dependable value assured as attainable under expected weather conditions, and (3) criteria for reliability in system planning to minimize the possibility of cascading outages of bulk power supply resources and facilities. The Guidelines were reviewed and revised in 1995 and presented in a new document entitled, "Principles and Guides for Reliability in System Planning", dated April 26, 1995. (See appendix B.) SERC has also endorsed the "NERC Planning Standards" approved by the NERC Board of Trustees, September 16, 1997. These guidelines are considered to be sound in principle and in keeping with good electric utility practices.

Caution must be exercised in utilizing the load forecasts in this document since peak loads are highly weather sensitive, and there is a high probability that peaks in excess of those estimated will be experienced should above-normal (in summer) or below-normal (in winter) temperatures occur. Member systems of SERC continue to use anticipated normal weather as a basis for load forecasts in accordance with NERC guidelines.

Since SERC covers such a large geographical area with wide ranges of temperatures, a considerable time diversity of peak loads may exist among its member systems. Thus, the summation of peak loads by seasons may not reflect the actual regional peaks.

Just as there is substantial uncertainty in the forecasts of future loads, the plans for future capacity are also uncertain. The tabulations in this report of future projects, particularly those in the second half of the reporting period, do not necessarily indicate a committed course of action. Uncertainties in the market conditions, financing, availability of sites, availability of usable fuel, the cost of fuel, demand-side management programs, environmental restrictions, regulatory action, the availability of non-utility generation, contractual arrangement, and other significant factors dictate a prudent approach of providing for alternate courses of action, wherever possible, so that the latest information may be used before a final decision is made.

Item 3.4, Planned Generators

ACAR Subregion

arolina Power & Light

Cogentrix-Elizabeth

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	NC	I	ST	0	33300	33300	BIT		OT	2000	11

Cogentrix-Kenansvil

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	NC	I	ST	0	32400	32400	BIT		OT	2001	9

Cogentrix-Roxboro

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	NC	I	ST	0	56000	56000	BIT		OT	2002	12

Cogentrix-Southport

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	NC	I	ST	0	107000	107000	BIT		OT	2002	12

ke Power Company

Buck

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
7	NC	U	GT	34855	0	0	OBG	NG	RT	2008	12
8	NC	U	GT	34855	0	0	OBG	NG	RT	2008	12
9	NC	U	GT	34855	0	0	OBG	NG	RT	2008	12

Buzzard Roost

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
6	SC	U	GT	22700	0	0	OBG	NG	RT	2008	12
7	SC	U	GT	22700	0	0	OBG	NG	RT	2008	12
8	SC	U	GT	22700	0	0	OBG	NG	RT	2008	12
9	SC	U	GT	22700	0	0	DFO	NG	RT	2008	12

Item 3.4, Planned Generators

\CAR Subregion

ke Power Company

Dan River

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
4	NC	U	GT	35240	0	0	DFO	NG	RT	2008	12
5	NC	U	GT	35240	0	0	DFO	NG	RT	2008	12
6	NC	U	GT	27490	0	0	DFO	NG	RT	2008	12

Riverbend

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
10	NC	U	GT	33800	0	0	DFO	NG	RT	2006	12
11	NC	U	GT	33800	0	0	DFO	NG	RT	2006	12
8	NC	U	GT	33800	0	0	DFO	NG	RT	2006	12
9	NC	U	GT	33800	0	0	DFO	NG	RT	2006	12

W S Lee

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
4	SC	U	GT	35100	0	0	DFO	NG	RT	2005	12
5	SC	U	GT	35100	0	0	DFO	NG	RT	2005	12
6	SC	U	GT	35100	0	0	DFO	NG	RT	2005	12

ıth Carolina Electric & Gas Company

Fairfield PS

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	SC	U	PS	63900	12000	12000	WAT		A	2003	6
2	SC	U	PS	63900	12000	12000	WAT		A	2003	6
3	SC	U	PS	63900	12000	12000	WAT		A	2001	6
4	SC	U	PS	63900	12000	12000	WAT		A	2001	6
5	SC	U	PS	63900	12000	12000	WAT		A	2004	6
6	SC	U	PS	63900	12000	12000	WAT		A	2004	6

NA 1

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
GT1	SC	U	GT	170000	150000	150000	NG	DFO	P	2005	5

ACAR Subregion

uth Carolina Electric & Gas Company

NA 5

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
NA5	SC	U	GT	170000	150000	150000	NG	DFO	P	2007	5

NA 8

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
GT8	SC	U	GT	170000	150000	150000	NG	DFO	P	2009	5

Urquhart

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	SC	U	CC	245000	170000	170000	NG	DFO	RP	2002	6
2	SC	U	CC	245000	170000	170000	NG	DFO	RP	2002	6

uth Carolina Public Service Authority

Horry LFG Site

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
HG1	SC	U	IC	1063	1063	1063	OBG		L	2001	8
HG2	SC	U	IC	1063	1063	1063	OBG		L	2001	8

John S Rainey

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
CT1A	SC	U	GT	165000	144000	179000	NG	DFO	V	2002	1
CT1B	SC	U	GT	165000	144000	179000	NG	DFO	V	2002	1
CT2A	SC	U	GT	165000	144000	179000	NG	DFO	U	2002	3
CT2B	SC	U	GT	165000	144000	179000	NG	DFO	U	2002	5
ST1S	SC	U	CA	190000	160000	179000	WH		V	2002	1

Unsited, Committed

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
CT1A	SC	U	GT	165000	144000	179000	NG	DFO	P	2004	1
CT1B	SC	U	GT	165000	144000	179000	NG	DFO	P	2004	1

Item 3.4, Planned Generators

\CAR Subregion

uth Carolina Public Service Authority

Unsited, Uncommitted

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
CT2A	SC	U	GT	165000	144000	179000	NG	DFO	P	2005	1
CT2B	SC	U	GT	165000	144000	179000	NG	DFO	P	2006	1
ST1S	SC	U	CA	190000	160000	179000	WH		P	2009	1

ginia Power Company

Cogentrix-Portsmouth

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	VA	I	ST	114750	-114360	-114360	BIT		RT	2008	6

International Paper

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	VA	I	ST	18600	-14000	-14000	BIT	WDS	RT	2006	8

Lakeview Hydro

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	VA	I	HY	400	-100	-100	WAT		RT	2008	12

Park 500

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	VA	I	ST	19620	-12000	-12000	BIT		RT	2003	12

Stone Container

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
1	VA	I	ST	48450	-38362	-38362	BIT	WDS	RT	2004	10

Undesignated Purchase

gen id	state	ownership	unit type	unit capacity, in kW nameplate	summer	winter	fuel type primary	alternate	status	in service date year	month
4	VA	U	OT	0	111000	111000	OTH		OT	2002	1
5	VA	U	OT	0	244000	244000	OTH		OT	2002	1
6	VA	U	OT	0	158000	158000	OTH		OT	2003	1

Item 3.4, Planned Generators

rginia Power Company

Wythe Park Power #2

gen id	state	ownership	unit type	unit capacity, in kW: nameplate	summer	winter	fuel type: primary	alternate	status	in service date: year	month
2	VA	I	IC	3562	-3000	-3000	DFO		RT	2004	12

Wythe Park Power #3

gen id	state	ownership	unit type	unit capacity, in kW: nameplate	summer	winter	fuel type: primary	alternate	status	in service date: year	month
3	VA	I	IC	3530	-3000	-3000	DFO		RT	2006	7

EXHIBIT 6

Energy Market Maps, South Atlantic Division, December 2001,
US Energy Information Administration

Map, South Carolina River Conservation Projects, SC Department of Natural Resources

Energy Market Maps **SOUTH ATLANTIC DIVISION** DECEMBER 2001

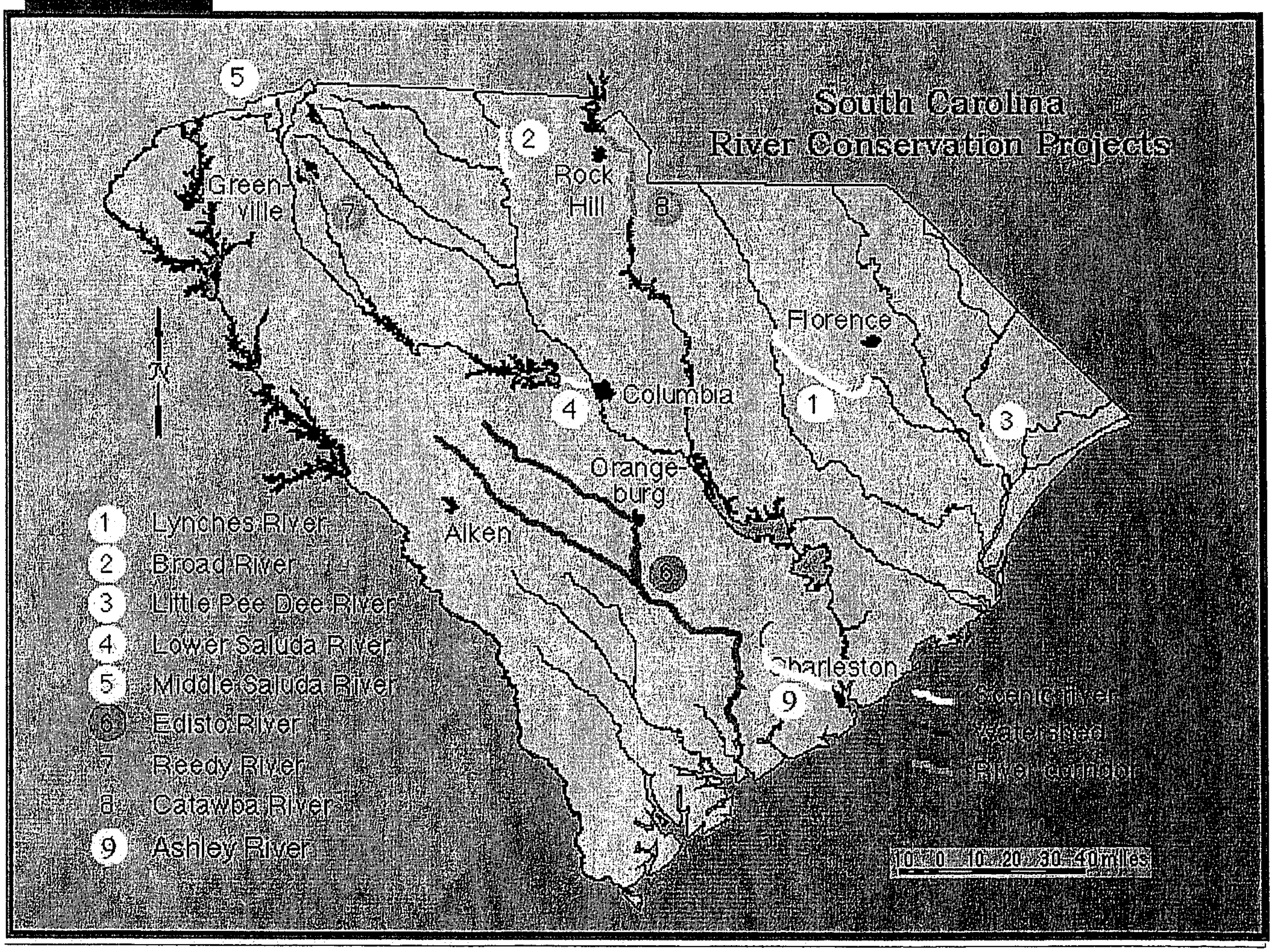
State Capitals | Major Cities | Clean City Programs | Major Cities with Clean City Programs

Electricity Plants (100 MW and greater) Coal | Natural Gas | Hydro | Wood | Wind | Nuclear | Petroleum | Geothermal | Trash | Solar

Energy Processing and Transmission Electricity Transmission Lines | Oil Ports | Oil Refineries | Natural Gas Pipeline Flow | Natural Gas Market Centers

- URL for this pdf page: http://www.eia.doe.gov/emeu/reps/states/maps/so_atl.pdf
- URL for the related html page: http://www.eia.doe.gov/emeu/reps/states/maps/so_atl.html
- Contact: Barbara.Fichman@eia.doe.gov ♦ 202-586-5737 ♦ Energy Information Administration
- File created: December 5, 2001

South Carolina
River Conservation Projects



SC Department of Natural Resources
Land, Water and Conservation Division
2221 Devine Street, Suite 222
Columbia, SC 29205
Phone: 803-734-9100 Fax: 803-734-9200

SCDNR Home Page

EXHIBIT 7

Map showing location of ozone monitors, Mapquest

Addresses and ID numbers of nearest ozone monitors
EPA AIR Data Monitor Address Reports

EPA AIR Data Monitor Values for selected monitors

EPA Air Data South Carolina Emissions Distribution by County
1999 Total Criteria Pollutant Emissions

MAPQUEST.

Charlotte, NC, 28273, US

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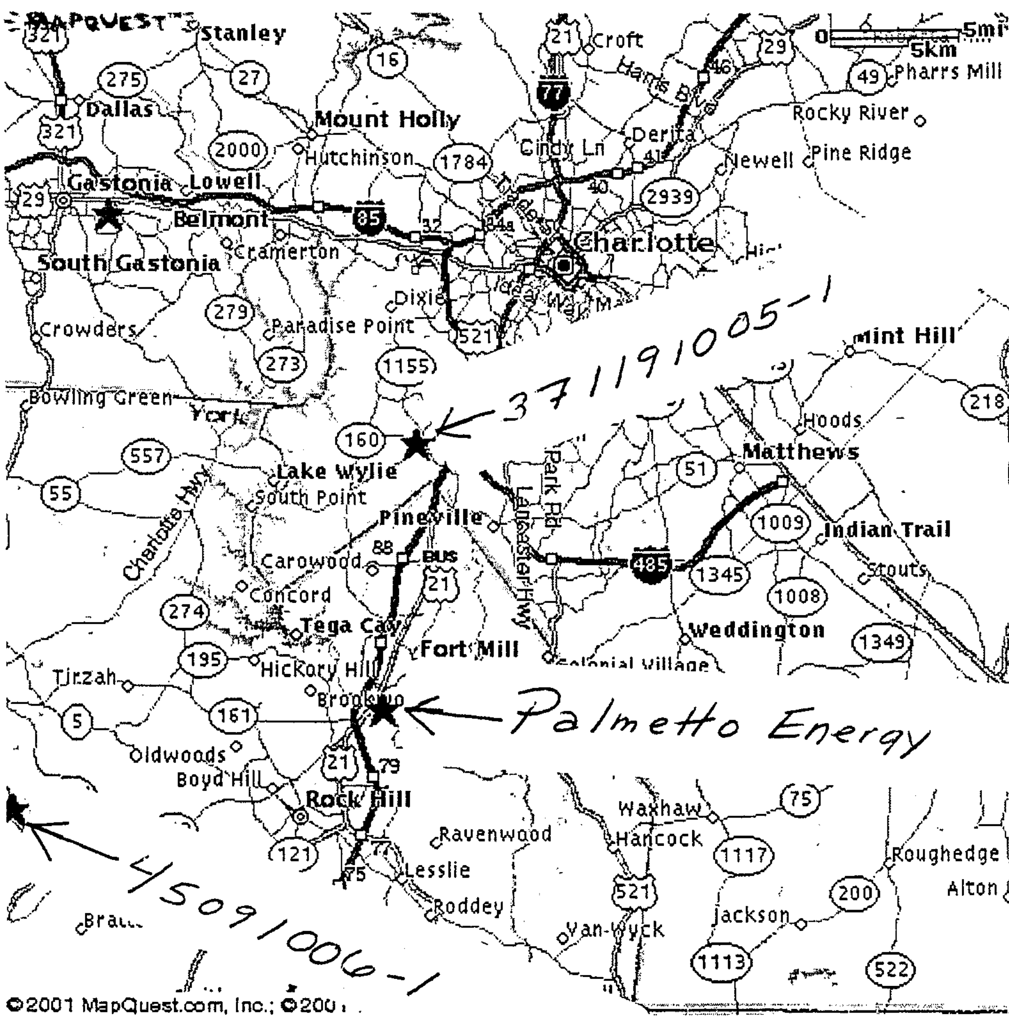
Back



1	04	SC	Spartanburg Co	Spartanburg	145 Spring Street	SLAMS,Other	Commercial	Urban / Center City	1996 - 2001	450830001	34.9475	-81.932
2	04	SC	Spartanburg Co		John Dodd Rd	NAMS	Residential	Rural	1996 - 2001	450830009	34.9886	-82.075
3	04	SC	Sumter Co	Sumter	Magnolia & Hampton	Other	Commercial	Urban / Center City	1996 - 2000	450850001	33.9222	-80.337
4	04	SC	Union Co		United Wood Yard Site	SLAMS	Forest	Rural	1996 - 2001	450870001	34.5389	-81.560
5	04	SC	Williamsburg Co		Hwy 216/512; 16 Miles East Of Kingstree	Other	Agricultural	Rural	1996 - 2001	450890001	33.7236	-79.565
6	04	SC	York Co	Rock Hill	Mt. Gallent @ Cherry Road	SLAMS,Other	Commercial	Suburban	1996 - 2001	450910005	34.9625	-81.000
7	04	SC	York Co		2395 Hwy 321 - Back Field	SLAMS	Agricultural	Suburban	1996 - 2001	450910006	34.9356	-81.228

rt this report to a text file i

e comma-delimited or tab-delimited values, compatible with PC spreadsheets and databases.

nma Tab

Report Criteria

laimer: AIR*Data* reports are produced from a monthly extract of EPA's air pollution database, AIRS. Data for this report were extracted on iary 04, 2002. They represent the best information available to EPA from state agencies on that date. However, some values may be absent due complete reporting, and some values subsequently may be changed due to quality assurance activities. The AIRS database is updated daily by and local organizations who own and submit the data. Please contact the pertinent state agency to report errors.

ders are cautioned not to infer a qualitative ranking order of geographic areas based on AIR*Data* reports. Air pollution levels measured in the ity of a particular monitoring site may not be representative of the prevailing air quality of a county or urban area. Pollutants emitted from a cular source may have little impact on the immediate geographic area, and the amount of pollutants emitted does not indicate whether the source mplying with applicable regulations.

AIRData

ffice of Air and Radiation

AIRData - Monitor Address Repo

February 27, 2002 50 Rows See Disclain

h Carolina Air Quality Monitors for Ozone (All Years)

/	Region	State	County	City	Site Address	Monitor Type	Land Use	Location Type	Years	Monitor ID	Latitude (Degrees)	Longitude (Degrees)
6	04	NC	Jackson Co		Barnet Knob Firetower Road	Tribal	Forest	Rural	1999 - 2001	370990005 - 1	35.5244	-83.236
7	04	NC	Johnston Co	Clayton	1338 Jack Road, Clayton Nc27520	SLAMS	Agricultural	Rural	1996 - 2001	371010002 - 1	35.5908	-78.461
8	04	NC	Lenoir Co	Kinston	Corner Hwy 70 East And 58 South	Other	Commercial	Suburban	1998 - 2001	371070004 - 1	35.2314	-77.568
9	04	NC	Lincoln Co	Lincolnton	Riverview Road	SLAMS	Residential	Rural	1996 - 2001	371090004 - 1	35.4383	-81.276
0	04	NC	Martin Co		Hayes Street (#2well Site)	SLAMS	Agricultural	Rural	1997 - 2001	371170001 - 1	35.8106	-76.906
1	04	NC	Mecklenburg Co	Charlotte	Plaza Road And Lakedell	NAMS	Residential	Suburban	1996 - 1999	371190034 - 1	35.2486	-80.766
2	04	NC	Mecklenburg Co	Charlotte	1120 Eastway Drive	NAMS	Residential	Urban / Center City	2000 - 2001	371190041 - 1	35.2403	-80.785
3	04	NC	Mecklenburg Co		400 Westinghouse Blvd.	SLAMS	Industrial	Rural	1996 - 2001	371191005 - 1	35.1131	-80.919
4	04	NC	Mecklenburg Co		29 N@ Mecklenburg Cab Co	NAMS	Agricultural	Rural	1996 - 2001	371191009 - 1	35.3486	-80.693
5	04	NC	New Hanover Co		6028 Holly Shelter Rd	SLAMS	Agricultural	Rural	1996 - 2001	371290002 - 1	34.3642	-77.838
6	04	NC	Northampton Co		Rt 46 Gaston North Carolina	Other	Commercial	Rural	1997 - 2001	371310002 - 1	36.4842	-77.619
7	04	NC	Person Co		Sr49	SLAMS	Agricultural	Rural	1998 - 2001	371450003 - 1	36.3069	-79.091
8	04	NC	Person Co		Sr 1102 & Nc 49	SLAMS	Agricultural	Rural	1997 - 1997	371450099 - 1	36.2806	-79.126

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AIRData - Monitor Values Repo

February 27, 2002 133 Rows See Disclain

EPA Air Quality Standa
0.12 ppm (1-hour averag

th Carolina Air Quality Monitors for Ozone (All Years)

	1-Hour Values					# Exceed						
)w #	# Obs	1st Max	2nd Max	3rd Max	4th Max	Actual	Est.	Year	City	County	State	Monitor ID
ORT												
1	209	0.094	0.092	0.089	0.089	0	0.0	2001		York Co	SC	450910006 - 1
2	212	0.093	0.089	0.088	0.087	0	0.0	2000		York Co	SC	450910006 - 1
3	194	0.119	0.114	0.107	0.104	0	0.0	1998		York Co	SC	450910006 - 1
4	209	0.114	0.107	0.104	0.102	0	0.0	1999		York Co	SC	450910006 - 1
5	194	0.114	0.105	0.103	0.103	0	0.0	1996		York Co	SC	450910006 - 1
6	211	0.108	0.098	0.095	0.090	0	0.0	1997		York Co	SC	450910006 - 1
7	213	0.083	0.080	0.077	0.075	0	0.0	2001		Williamsburg Co	SC	450890001 - 2
8	213	0.095	0.092	0.088	0.083	0	0.0	2000		Williamsburg Co	SC	450890001 - 2
9	180	0.094	0.090	0.088	0.087	0	0.0	1998		Williamsburg Co	SC	450890001 - 2
10	207	0.086	0.084	0.078	0.078	0	0.0	1997		Williamsburg Co	SC	450890001 - 2
11	189	0.097	0.089	0.089	0.085	0	0.0	1999		Williamsburg Co	SC	450890001 - 2
12	211	0.092	0.085	0.082	0.081	0	0.0	1996		Williamsburg Co	SC	450890001 - 2
13	209	0.100	0.095	0.090	0.089	0	0.0	2001		Union Co	SC	450870001 - 1
14	210	0.096	0.093	0.089	0.088	0	0.0	2000		Union Co	SC	450870001 - 1
15	214	0.116	0.099	0.099	0.096	0	0.0	1999		Union Co	SC	450870001 - 1
16	208	0.092	0.091	0.089	0.088	0	0.0	1996		Union Co	SC	450870001 - 1
17	210	0.098	0.098	0.093	0.092	0	0.0	1997		Union Co	SC	450870001 - 1
18	200	0.111	0.105	0.100	0.099	0	0.0	1998		Union Co	SC	450870001 - 1
19	202	0.113	0.108	0.105	0.104	0	0.0	2001		Spartanburg Co	SC	450830009 - 1
20	212	0.123	0.110	0.105	0.103	0	0.0	2000		Spartanburg Co	SC	450830009 - 1
21	185	0.123	0.122	0.112	0.108	0	0.0	1999		Spartanburg Co	SC	450830009 - 1
22	196	0.120	0.111	0.106	0.103	0	0.0	1998		Spartanburg Co	SC	450830009 - 1

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February 27, 2002 254 Rows See Disclain

th Carolina Air Quality Monitors for Ozone (All Years)

EPA Air Quality Standaı
0.12 ppm (1-hour averag

	1-Hour Values					# Exceed							
›w #	# Obs	1st Max	2nd Max	3rd Max	4th Max	Actual	Est.	Year	City	County	State	Region	Monitor ID
ORT													
151	213	0.102	0.100	0.099	0.099	0	0.0	1996	Lincolnton	Lincoln Co	NC	04	371090004 - 1
152	211	0.091	0.088	0.087	0.086	0	0.0	2001		Martin Co	NC	04	371170001 - 1
153	211	0.096	0.095	0.091	0.091	0	0.0	2000		Martin Co	NC	04	371170001 - 1
154	210	0.103	0.102	0.089	0.088	0	0.0	1999		Martin Co	NC	04	371170001 - 1
155	211	0.103	0.094	0.092	0.092	0	0.0	1998		Martin Co	NC	04	371170001 - 1
156	214	0.094	0.092	0.090	0.090	0	0.0	1997		Martin Co	NC	04	371170001 - 1
157	214	0.130	0.125	0.123	0.116	2	2.0	1999	Charlotte	Mecklenburg Co	NC	04	371190034 - 1
158	214	0.142	0.125	0.116	0.112	2	2.0	1996	Charlotte	Mecklenburg Co	NC	04	371190034 - 1
159	214	0.123	0.120	0.118	0.118	0	0.0	1997	Charlotte	Mecklenburg Co	NC	04	371190034 - 1
160	212	0.130	0.129	0.124	0.120	2	2.0	1998	Charlotte	Mecklenburg Co	NC	04	371190034 - 1
161	198	0.121	0.119	0.115	0.111	0	0.0	2001	Charlotte	Mecklenburg Co	NC	04	371190041 - 1
162	212	0.152	0.130	0.127	0.117	3	3.0	2000	Charlotte	Mecklenburg Co	NC	04	371190041 - 1
163	211	0.121	0.116	0.101	0.095	0	0.0	2001		Mecklenburg Co	NC	04	371191005 - 1
164	212	0.140	0.135	0.132	0.120	3	3.0	1998		Mecklenburg Co	NC	04	371191005 - 1
165	212	0.124	0.114	0.110	0.106	0	0.0	1997		Mecklenburg Co	NC	04	371191005 - 1
166	209	0.131	0.130	0.116	0.111	2	2.0	1996		Mecklenburg Co	NC	04	371191005 - 1
167	214	0.132	0.130	0.128	0.121	3	3.0	1999		Mecklenburg Co	NC	04	371191005 - 1
168	214	0.119	0.104	0.104	0.103	0	0.0	2000		Mecklenburg Co	NC	04	371191005 - 1
169	213	0.128	0.120	0.119	0.109	1	1.0	2001		Mecklenburg Co	NC	04	371191009 - 1
170	212	0.144	0.141	0.121	0.119	2	2.0	2000		Mecklenburg Co	NC	04	371191009 - 1
171	212	0.122	0.121	0.117	0.116	0	0.0	1999		Mecklenburg Co	NC	04	371191009 - 1
172	212	0.134	0.125	0.124	0.123	2	2.0	1998		Mecklenburg Co	NC	04	371191009 - 1

AIRData
A Office of Air and Radiation

Emissions Distribution Ma

February 27, 2002 See Disclair

th Carolina Emissions Distribution By County -- 1999 Total Criteria Pollutant Emissions

See zoom and pan instructions below this image

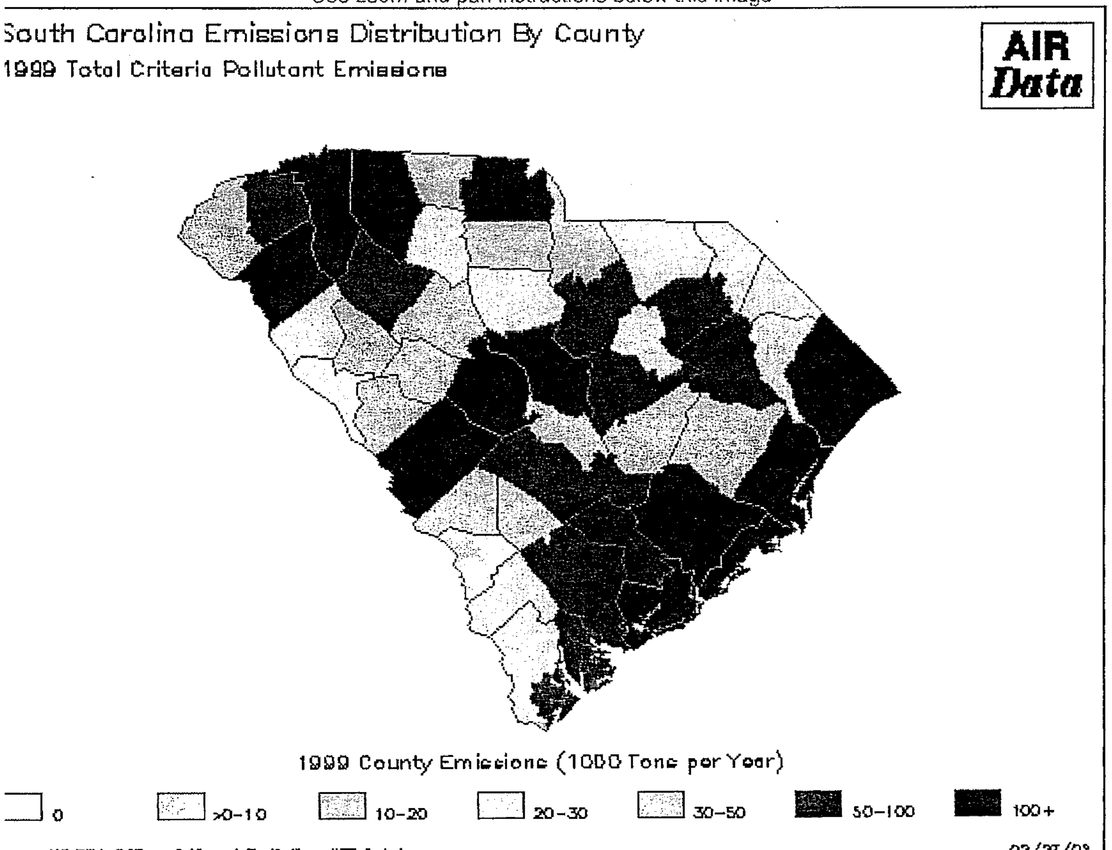

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EXHIBIT 8

South Carlina Department of Health and Environmental Control
Boundary Recommendations for South Carolina for the Remanded
8- hour ozone standard, July 14, 200
Cover, TOC, pp. 1, 2, 10, Map 1

Boundary Recommendations for South Carolina for the Remanded 8-Hour Ozone Standard

D H E C

PROMOTE PROTECT PROSPER

South Carolina Department of Health
and Environmental Control

July 14, 2000

Table of Contents

Summary of Boundary Recommendations for the Remanded 8-Hour Ozone Standard in South Carolina

The 8-hour ozone boundary recommendations submitted herein are to fulfill our obligation under the Clean Air Act and the Transportation Equity Act for the 21st Century (TEA-21). These recommendations are submitted with great reluctance and strong objection due to the fact that this matter is still under litigation and is currently under review by the U.S. Supreme Court. Using the Environmental Protection Agency's (EPA) guidance, several areas of the state are being recommended for non-attainment designation using 1997-1999 monitored ozone data. The South Carolina Department of Health and Environmental Control (Department) requests the courtesy of consulting with EPA as this information is reviewed. Should circumstances dictate the delay of designations by EPA, we request to be provided the opportunity to use the most recent data available for determining boundaries and designations before proposed and/or final designations are made.

South Carolina's boundary recommendations for the non-attainment designation of the remanded 8-hour ozone standard are the seven distinct Metropolitan Planning Organization (MPO) boundaries. This recommendation is based upon data from monitors representing the urbanized portions of Anderson, Aiken, Columbia, Florence, Greenville, Spartanburg, and Rock Hill. These areas form the MPO boundaries that are shown on Map 1 and identified separately in the following pages.

These MPOs capture the most urbanized portions of the state that have ozone design values above the remanded 8-hour standard. Additionally, much of the detailed data needed for transportation planning and conformity determinations is based on the MPO boundaries. Although we are recommending smaller non-attainment boundaries to ensure public health protection and attainment of all National Ambient Air Quality Standards (NAAQS), it is important to know that further controls will be considered for industries and mobile sources outside of the non-attainment boundaries. South Carolina has the statutory authority to require statewide controls of all regulated pollutants and will seek any necessary control strategies to address ozone precursors (volatile organic compounds and oxides of nitrogen).

South Carolina currently has two separate standards that regulate volatile organic compound (VOC) emissions. South Carolina Regulation 61-62.5, Standard 5.1, Lowest Achievable Emission Rate (LAER) applies to all new, modified, or altered sources that would increase emissions of VOCs. LAER is applied to new construction or modifications when the net VOC emissions increase exceeds 100 tons per year.

In addition, Regulation 61-62.5, Standard 5, outlines the Reasonably Available Control Technology (RACT) for VOCs. This standard applies to existing processes statewide with the exception of the following six counties: Anderson, Bamberg, Barnwell, Chesterfield, Darlington and Hampton. We are considering revising this standard to remove the exemption for the six counties listed above.

The Department continues to be very supportive of the EPA's Tier 2 and low sulfur fuel regulations, finalized February 10, 2000, making passenger cars, light trucks, and larger passenger vehicles even cleaner beginning in 2004. The regulation focuses on reducing the emissions most responsible for ozone formation and particulate matter (PM) impact from these vehicles. For the first time, the same set of federal standards will apply to all passenger cars, light trucks, and medium-duty passenger vehicles, ensuring that essentially all future passenger-use vehicles will be very clean vehicles. Another part of this regulation significantly reduces the average gasoline sulfur levels nationwide to a 30 ppm average and a 80 ppm cap by 2006. We feel that the implementation of these regulations will provide significant assistance towards statewide compliance with the NAAQS in the areas where it is needed the most, our urbanized areas. The full extent of that benefit is not yet known. On May 1, 2000, we requested from EPA an analysis similar to one they had performed for another state detailing expected emission reductions from the above regulations. Fulfilling our request would have assisted us in verifying the necessary size of our boundary recommendation; however, our request was denied by EPA on May 10, 2000. [see Appendix G]

The Department also supports a national approach to address both diesel fuel and heavy-duty diesel engine emissions. South Carolina citizens would receive tremendous air quality benefits from a national program that addresses heavy-duty diesel emissions and low-sulfur diesel fuel. The Department has encouraged EPA to take the necessary steps to enact, by no later than 2007, more stringent on-road and non-road heavy-duty diesel emission standards.

The Department is involved in the oxides of nitrogen (NOx) State Implementation Plan (SIP) Call and plans to participate fully, as appropriate, once the courts have fully resolved this matter. Additionally, the Department has the authority to require controls on any source that impacts the ambient air quality. Once litigation of the remanded 8-hour ozone standard is resolved, South Carolina will pursue any necessary additional controls on industry and transportation.

The health of our citizens is a primary concern and even though South Carolina is in attainment with the 1-hour ozone standard we continue to seek proactive measures to meet our commitment to public health and environmental protection. An example of these measures is our "Spare the Air" campaign which forecasts ozone levels based on the 8-hour ozone standard and assures public awareness by providing local air quality advisories through our state-wide voluntary ozone awareness network. The advisories are available daily through various media (i.e., newspapers, television, Internet, etc.). By providing these forecasts we hope to raise awareness and influence our citizens' behaviors in a way that will result in ground-level ozone reductions.

Funds have been made available through a supplemental environmental project for the Rock Hill/Fort Mill MPO area to create stations for ethanol distribution. This initiative, funded from an EPA enforcement action, is the result of creative foresight by the Department, the South Carolina Energy Office, and the Catawba Regional Council of Governments. These stations will create greater access to ethanol for the growing fleet of flexible fuel vehicles in York, Lancaster, Chester, and Cherokee counties. This project will provide air quality benefits for both South Carolina and North Carolina.

Additional data and appendices to support the MPO boundaries as the recommended non-attainment areas are provided in the following sections. The criteria for the data is specific to the individual MPO and is consistent with the limited guidance provided by EPA.

Rock Hill/Fort Mill MPO

The Rock Hill/Fort Mill MPO includes that portion of York County distinctly defined and known as the Rock Hill/Fort Mill Transportation Area Study. The city of Rock Hill is included within the MPO boundary. The Rock Hill/Fort Mill MPO is one of two South Carolina urbanized areas included in a MPO that borders with another state's urbanized area. While South Carolina is committed to working with the other states to assure mutual attainment of the remanded 8-hour ozone standard, we specifically request that should EPA proceed with non-attainment designation that EPA delineate South Carolina's boundaries independent from any adjacent state's non-attainment area. This will facilitate areas of non-attainment being re-designated as attainment as expeditiously as possible.

The ambient air quality impacts from the area are measured by two monitors that account for south westerly meteorological patterns. The state of North Carolina operates monitors directly across the state line that provide data for conditions northeast of the MPO. The general flow of surface air is out of the southwest, but wind patterns during days of ozone standard exceedances do not indicate a consistent wind pattern.

The topography of the MPO area is predominantly flat with no barriers to ambient air transport.

The Catawba Indian lands are located within the MPO boundary and have representation on the MPO.

York County has a mixed land use pattern that is mostly rural. The exception is the MPO area which is mostly urban. The MPO is located in the northeast portion of the county. The county as a whole is 695.8 sq. miles in size with a total population of 158,180. Similar data from the MPO (175.3 sq. mi. with a population of 113,300), yields a MPO population density of 646.4 persons/sq. mi. compared to a non-MPO population density of 86.2 persons/sq. mi. in York County.

Population projections between 1999 and 2015 estimate that the MPO area and the county as a whole will grow by about 25%.

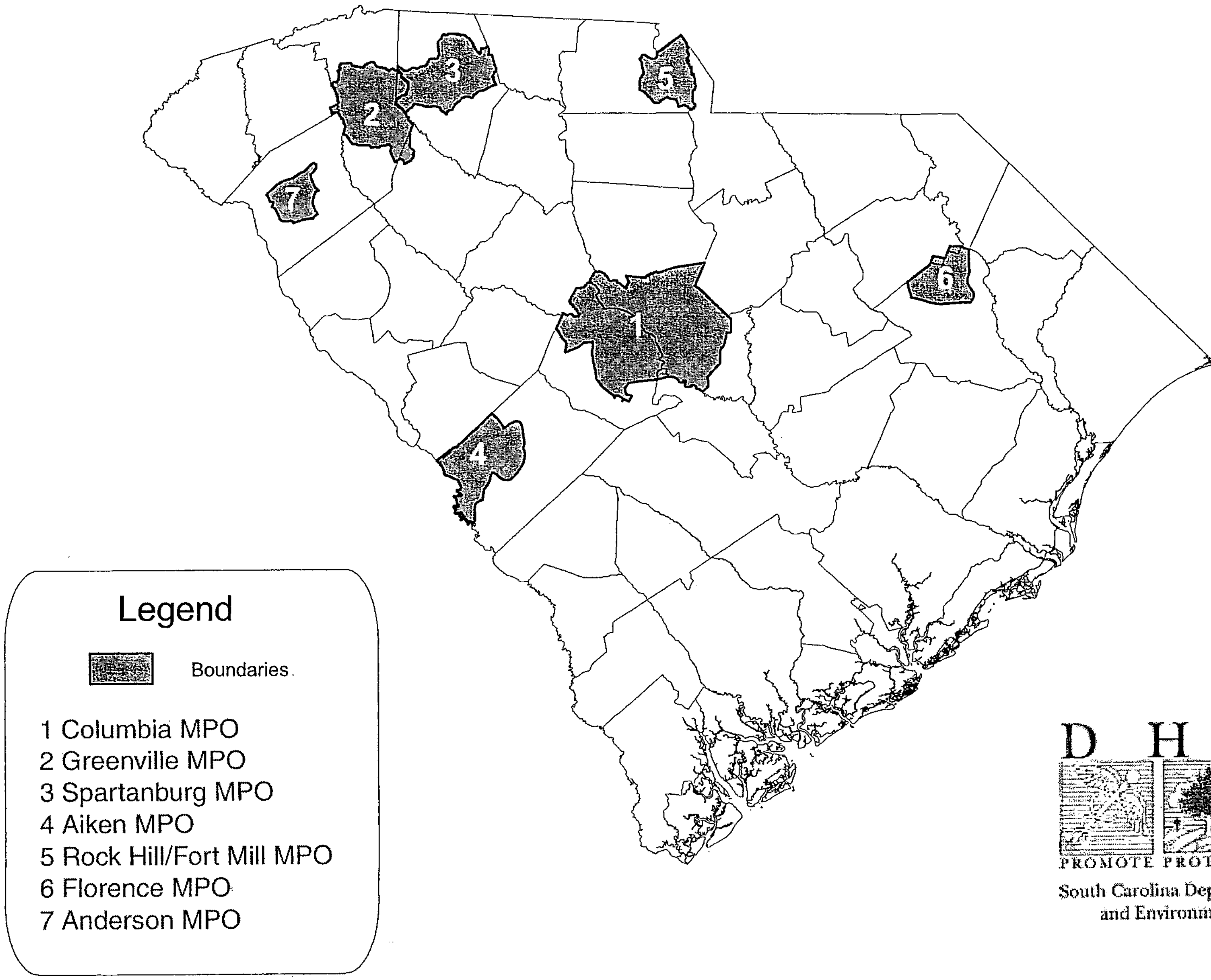
Over 69% of the daily vehicle miles traveled in York County occur within the MPO boundary.

Of the 10 stationary sources of NOx emissions in York County, 5 are located within the MPO. They account for 99% of the 4,944.2 tons of NOx emitted annually from the whole county. In addition, 4,799 tons, or 97%, of NOx are emitted from two facilities. Both facilities are subject to potential impacts of the NOx SIP Call.

Of the 10 stationary sources of VOC emissions in York County, 6 are located within the MPO. They account for over 95% of the 3,227.1 tons of VOC emitted annually from the county as a whole.

Additional data and various maps supporting our recommendation of the Rock Hill/Fort Mill MPO can be found in the appendices.

Proposed Boundary Recommendations for the Remanded 8-hr Ozone Standard



DHEC
PROMOTE PROTECT PROSPER
South Carolina Department of Health and Environmental Control

EXHIBIT 9

EPA page directing users to Scorecard

Scorecard Health Ranking of Formaldehyde in York County, SC

Scorecard Air Emissions Ranking of Formaldehyde by Counties in US

Article X Application, Wawayanda Energy Center, Calpine
Table 6-22, Non Criteria Pollutant Emission from Combustion Turbines

DHEC Air Modeling Standards, pp. 52 – 57

EPA United States Environmental Protection Agency

Envirofacts Warehouse Chemical References

Index | Query | Model | Feedback | EF Home

Envirofacts Warehouse Chemical References

SULFUR DIOXIDE CAS #7446-09-5

The following information resources are not maintained by Envirofacts. Envirofacts is neither responsible for their informational content nor for their site operation, but provides references to them here as a convenience to our Internet users.

Reference information on this chemical can be found at the following locations:

Non-Governmental Organizations

- The Environmental Defense Fund's EXIT EPA **Chemical Scorecard** summarizes information about health effects, hazard rankings, industrial and consumer product uses, environmental releases and transfers, risk assessment values and regulatory coverage.

These pages are maintained by the Envirofacts Support Team at the EPA Systems Development Center.
For comments, problems or suggestions, please use the Envirofacts Feedback Form.

This page was updated July 23, 1998.

This document contains the following shortcuts:

Shortcut Text	Internet Address
	http://www.epa.gov/
	http://www.epa.gov/enviro/maps/chemref.map
Chemical Scorecard	http://www.scorecard.org/chemical-profiles/summary.tcl?edf_substance_id=7446-09-5
Envirofacts Feedback Form.	http://www.epa.gov/enviro/html/ef_feedback.html

EPA - PAGE showing EPA direct link to chemical scorecard "credible site"

POLLUTION LOCATOR | Hazardous Air Pollutants | Source Categories Contributing to Chemical-specific Risks

ENVIRONMENTAL DEFENSE
finding the ways that work

County: YORK

HAP	Sort by Added Cancer Risk (per 1,000,000)	Sort by Noncancer Hazard Index	Percent Emitted from Point Sources	Percent Emitted from Area Sources	Percent Emitted from Mobile Sources	Percent from Background Levels
ACROLEIN	--	1.6	0.15%	41%	58%	0%
FORMALDEHYDE	6.1	0.34	13%	18%	45%	23%
DIESEL EMISSIONS	420	0.28	0%	0%	61%	39%
LEAD	0.14	0.077	3.7%	83%	14%	0%
ACETALDEHYDE	1.4	0.056	1.6%	12%	87%	0%
CARBON TETRACHLORIDE	37	0.022	0.00078%	0.022%	0%	100%
CHROMIUM	22	0.018	3.3%	95%	1.7%	0%
BENZENE	31	0.018	0.14%	7.4%	48%	45%
NICKEL	0.23	0.017	13%	84%	2.9%	0%
MANGANESE	--	0.014	43%	55%	1.4%	0%
ARSENIC	1.3	0.013	91%	9.0%	0.071%	0%
BERYLLIUM	0.027	0.011	35%	65%	0%	0%
1,2-DIBROMOETHANE	0.55	0.0096	0.00041%	0.023%	0%	100%
TOLUENE	--	0.0059	9.6%	18%	72%	0%
TETRACHLOROETHYLENE	1.2	0.0052	1.7%	34%	0%	65%
1,3-BUTADIENE	9.0	0.0027	0.29%	22%	78%	0%
1,3-DICHLOROPROPENE (MIXED ISOMERS)	0.66	0.0021	0%	100%	0%	0%
CADMIUM	0.074	0.0021	50%	50%	0%	0%
MERCURY	--	0.0018	77%	18%	4.7%	0%
XYLENE (MIXED ISOMERS)	--	0.0018	8.9%	15%	62%	14%
DICHLOROMETHANE	0.34	0.00086	26%	33%	0%	41%
ACRYLONITRILE	0.22	0.00038	0.0046%	100%	0%	0%
POLYCHLORINATED BIPHENYLS	0.22	0.00032	0.014%	0%	0%	100%
CHLOROFORM	0.43	0.00027	0.0033%	1.4%	0%	99%

Health risk

e
ENVIRONMENTAL DEFENSE
finding the ways that work

ABOUT THE CHEMICALS | By County

Chemical: formaldehyde
CAS Number: 50-00-0

Counties with Reported Air Releases

Ranked by (select your ranking criteria)

Air releases
in
Entire United States Go (explain)

Rank	County	Pounds
1.	CHATHAM, NC	354,559
2.	MARLBORO, SC	352,854
3.	FLATHEAD, MT	348,250
4.	DEFIANCE, OH	344,717
5.	KING WILLIAM, VA	338,835
6.	MONROE, AL	329,455
7.	MCMINN, TN	305,778
8.	MCCURTAIN, OK	267,373
9.	HARRIS, TX	261,906
10.	LANE, OR	236,527
11.	LICKING, OH	230,560
12.	WOOD, WI	225,949
13.	NUECES, TX	170,652
14.	BIBB, GA	159,348
15.	LINN, OR	158,088

63rd highest air releases formaldehyde

16.	MCKEAN, PA	157,166
17.	HOT SPRING, AR	152,529
18.	JACKSON, OR	141,485
19.	ORANGEBURG, SC	135,472
20.	MORGAN, AL	135,231
21.	BERKELEY, SC	131,451
22.	MCPHERSON, KS	126,200
23.	FULTON, GA	118,733
24.	MISSOULA, MT	117,011
25.	NACOGDOCHES, TX	104,637
26.	COLUMBUS, NC	102,400
27.	DESCHUTES, OR	94,897
28.	WYANDOTTE, KS	94,310
29.	RUSSELL, AL	93,529
30.	SURRY, NC	90,516
31.	KLAMATH, OR	89,609
32.	GLENN, CA	88,914
33.	ELLIS, TX	88,730
34.	COWLITZ, WA	83,203
35.	NEW CASTLE, DE	83,012
36.	ATKINSON, GA	80,422
37.	OTSEGO, MI	78,513
38.	DOUGLAS, OR	78,074
39.	MADISON, IL	78,000
40.	SMITH, MS	77,520
41.	TUSCALOOSA, AL	76,225
42.	DE SOTO, LA	76,088
43.	PIKE, MO	76,000
44.	MIDLAND, MI	74,007
45.	COSHOCTON, OH	70,720
46.	RIVERSIDE, CA	69,044
47.	LANCASTER, PA	65,647
48.	LAFAYETTE, MS	64,520
49.	LUCAS, OH	64,235

49.	LUCAS, OH	64,255
50.	CLARION, PA	63,850
51.	FAYETTE, WV	62,413
52.	HAMPTON, SC	62,339
53.	WOOD, WV	60,998
54.	JONES, MS	60,958
55.	JOHNSON, TX	60,503
56.	SUSSEX, VA	60,124
57.	LINCOLN, LA	57,385
58.	SANTA CLARA, CA	57,176
59.	ISLE OF WIGHT, VA	54,436
60.	GRENADA, MS	53,957
61.	UNION, OR	53,690
62.	ASHLEY, AR	53,100
63.	YORK, SC	52,870
64.	AROOSTOOK, ME	52,570
65.	MOBILE, AL	52,549
66.	NASSAU, FL	52,124
67.	BRADFORD, PA	51,336
68.	WINSTON, MS	50,088
69.	SAWYER, WI	50,054
70.	CHARLESTON, SC	49,062
71.	HUBBARD, MN	48,652
72.	DOOLY, GA	47,328
73.	RICHLAND, SC	46,849
74.	AMADOR, CA	46,847
75.	HUMBOLDT, CA	46,000
76.	HENDRY, FL	45,980
77.	ALBANY, NY	45,932
78.	ST. CHARLES, LA	45,670
79.	NEW HANOVER, NC	45,600
80.	NEW HAVEN, CT	45,343
81.	MADERA, CA	44,795
82.	HARDIN, TX	43,330

Average Annual Heat Input Rate	1845	MMBtu/hr
Annual Operating Hours	8760	hrs/yr/turbine
No. of turbines	2	

Pollutant	Notes	Emission Factor (lb/mmBtu) w/o oxidation catalyst	Emission Factor (lb/mmBtu) w/ oxidation catalyst [5]	Annual Potential Emissions [6] (Total for both turbines) w/o oxidation catalyst	Annual Potential Emissions [6] (Total for both turbines) w/ oxidation catalyst
		Natural Gas Turbine		(ton/yr)	
1,3-Butadiene	(1)	< 4.30E-07	N/A	< 6.95E-03	N/A
Acenaphthene	(2)	< 8.53E-08	N/A	< 1.38E-03	N/A
Acenaphthylene	(2)	< 8.53E-08	N/A	< 1.38E-03	N/A
Acetaldehyde	(1)	4.00E-05	1.76E-04	6.47E-01	2.85E+00
Acrolein	(1)	6.40E-06	3.62E-06	1.03E-01	5.85E-02
Anthracene	(2)	< 1.14E-07	N/A	< 1.84E-03	N/A
Benz(a)anthracene	(2)	< 8.53E-08	N/A	< 1.38E-03	N/A
Benzene	(1)	1.20E-05	3.26E-06	1.94E-01	5.27E-02
Benzo(a)pyrene	(2)	< 5.69E-08	N/A	< 9.20E-04	N/A
Benzo(b)fluoranthene	(2)	< 8.53E-08	N/A	< 1.38E-03	N/A
Benzo(g,h,i)perylene	(2)	< 5.69E-08	N/A	< 9.20E-04	N/A
Benzo(k)fluoranthene	(2)	< 8.53E-08	N/A	< 1.38E-03	N/A
Chrysene	(2)	< 8.53E-08	N/A	< 1.38E-03	N/A
Dibenz(a,h)anthracene	(2)	< 5.69E-08	N/A	< 9.20E-04	N/A
Ethylbenzene	(1)	3.20E-05	N/A	5.17E-01	N/A
Fluoranthene	(2)	1.42E-07	N/A	2.30E-03	N/A
Fluorene	(2)	1.33E-07	N/A	2.15E-03	N/A
Formaldehyde	(3)	5.60E-04	3.60E-06	9.05E+00	5.82E-02
Indeno(1,2,3-cd)pyrene	(2)	< 8.53E-08	N/A	< 1.38E-03	N/A
Naphthalene	(1)	1.30E-06	N/A	2.10E-02	N/A
Phenanthrene	(2)	8.06E-07	N/A	1.30E-02	N/A
Propylene Oxide	(1)	< 2.90E-05	N/A	< 4.69E-01	N/A
Pyrene	(2)	2.37E-07	N/A	3.83E-03	N/A
Sulfuric Acid Emissions	(4)	5.25E-04	N/A	8.49E+00	N/A
Toluene	(1)	1.30E-04	N/A	2.10E+00	N/A
Xylene	(1)	6.40E-05	N/A	1.03E+00	N/A

Emission factors prefixed with a "less than" symbol (<) indicate that the compound was not detected.
The presented emission value is based on one-half of the detection limit.

Natural Gas Fuel HHV	1000	Btu/scf
Total turbine PAH	2.20E-06	lb/mmBtu from AP-42 Table 3.1-3

Pollutant	AP-42 Emission Factor (lb/mmCF)	Percent of Total (%)	Calculated Emission Factor (lb/mmBtu)
Acenaphthene	1.80E-06	3.88%	8.53E-08
Acenaphthylene	1.80E-06	3.88%	8.53E-08
Anthracene	2.40E-06	5.17%	1.14E-07
Benz(a)Anthracene	1.80E-06	3.88%	8.53E-08
Benzo(a)pyrene	1.20E-06	2.59%	5.69E-08
Benzo(b)fluoranthene	1.80E-06	3.88%	8.53E-08
Benzo(g,h,I)perylene	1.20E-06	2.59%	5.69E-08
Benzo(k)fluoranthene	1.80E-06	3.88%	8.53E-08
Chrysene	1.80E-06	3.88%	8.53E-08
Dibenzo(a,h)anthracene	1.20E-06	2.59%	5.69E-08
Fluoranthene	3.00E-06	6.47%	1.42E-07
Fluorene	2.80E-06	6.03%	1.33E-07
Indeno(1,2,3-cd)pyrene	1.80E-06	3.88%	8.53E-08
Phenanathrene	1.70E-05	36.64%	8.06E-07
Pyrene	5.00E-06	10.78%	2.37E-07
Totals	4.64E-05	100.00%	2.20E-06

AP-42 Emission factors from AP-42 Table 1.4-3 (dated 7/1998)

(1) Turbine emission data from AP-42 Section 3.1 Table 3.1-3 (dated 4/2000).

(2) PAHs are broken out for turbines using the same speciation for boilers in AP-42:

(3) Based on Calpine test data.

(4) Sulfuric acid emissions are based on the sulfur content of the fuel and 15% conversion of SO2 to SO3 and assume 100% of SO_3 (MW=80) converts to H_2SO_4 (MW=98).

61-62.5, Standard No. 8, Toxic Air Pollutants.

I. GENERAL APPLICABILITY. This Standard is applicable to sources of toxic air pollutants as provided below. This Standard does not apply to fuel burning sources which burn only virgin fuel or specification used oil. The terms in this Standard are used as defined in South Carolina Air Pollution Control Regulations and Standards Regulation 62.1, Section I, "Definitions". The effective date of this Standard is June 28, 1991.

A. EXISTING SOURCES:

(1) Any person with an existing source of any toxic air pollutant shall be required to show compliance with this standard not later than two years after the effective date of this standard. These sources must provide the Department with the name and Chemical Abstract Service(CAS) number of the chemical, stack parameters, and emission rate data. If potential emissions of any single toxic air pollutant are 1000 lbs/month or greater an operating permit will be required. An operating permit may or may not be required for sources with emissions less than 1000 lbs/month. This determination will take into consideration, but not be limited to, the nature and amount of the pollutants, location, proximity to commercial establishments and residences.

(2) Any person holding an operating permit prior to the effective date of this standard shall be required to demonstrate compliance with this standard for all toxic air pollutant emissions prior to renewal of the operating permit. The compliance demonstration must include all sources of toxic air pollutants at the facility, including sources not previously subject to permit requirements. Methods for compliance demonstration may be found in the *Air Quality Modeling Guidelines* as prepared pursuant to paragraph II (A) of this regulation.

B. NEW SOURCES: Any person who constructs, alters, or adds to a source of toxic air pollutants after the effective date of this standard, shall comply with this standard. These sources must provide the Department with the name and Chemical Abstract Service (CAS) number of the chemical, stack parameters, and emission rate data. If potential emissions of any single toxic air pollutant are 1000 lbs/month or greater a construction permit will be required. A permit may or may not be required for sources with emissions less than 1000 lbs/month; however, all sources are required to demonstrate compliance with this standard for all toxic emissions. This determination will take into consideration, but will not be limited to, the nature and amount of the pollutants, location, proximity to residences and commercial establishments. Methods for compliance demonstration may be found in the Air Quality Modeling Guidelines as prepared pursuant to paragraph II(A) of this regulation.

C. This standard will not supersede any requirements imposed by Federal National Emission Standards for Hazardous Air Pollutants nor any special permit conditions, unless this standard would impose a more restrictive emission limit.

D. Facilities are exempt from the requirements of this standard as follows:

(1) Affected sources that emit Hazardous Air Pollutants (HAPs) (42 U.S.C. 112(b)) and are subject to one or more Federal Maximum Achievable Control Technology (MACT) standards (42 U.S.C. 112(d), (g), (h), or (j)) are exempt. This exemption shall only apply to toxic air pollutants regulated by this standard that are also federally regulated HAPs, except as provided below. This exemption shall apply once the emission sources are in compliance with a proposed or final MACT standard. Affected source, for the purposes of this part, means the stationary source, the group of stationary sources, or the portion of a stationary source that is regulated by a relevant standard or other requirement established pursuant to Section 112 of the Act (42 U.S.C 7401 et seq.). Each relevant standard will define the "affected source" for the purposes of that standard.

(2) Emission points that emit HAPs which are not exempt from this standard according to (1) above are granted an exemption once a federally required Residual Risk analysis (42 U.S.C. section 112(f)) that accounts for all facility-wide HAPs has been completed. Such emission points may be exempted prior to a Residual Risk analysis on a case-by-case basis after review by the Department. Exemptions may be granted in cases where off-site impacts from HAP emissions are significantly below levels established by this standard (less than 50% of the standard).[1]

(3) Sources that emit toxic air pollutants regulated by this standard which are not federally regulated HAPs can request an exemption from this standard on a case-by-case basis after review by the Department. Exemptions may be granted in cases where non-HAP emissions are controlled (reduced) by MACT controls applied to reduce HAP emissions and in cases where off-site impacts from non-HAP emissions are significantly below levels established by this standard (less than 50% of the standard).[1]

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1 If future construction/modifications cause off-site impacts to exceed 50% of the appropriate standard, the exemption is no longer valid.

E. Additions and deletions to the list of Toxic Air Pollutants may be made following normal administrative procedures.

II. TOXIC AIR EMISSIONS.

A. The Department will prepare Air Quality Modeling Guidelines to provide assistance to facilities concerning compliance demonstrations and modeling issues. These guidelines may be updated periodically as new models and/or modeling procedures are developed by the Environmental Protection Agency. Detailed procedures for showing compliance with this standard may be found in the Air Quality Modeling Guidelines. Required modeling must use the latest versions of United States Environmental Protection Agency air dispersion models to determine the concentration of the toxic air pollutant in the ambient air at or beyond the plant property line, using 24-hour averaging.

B. The Bureau may provide modeling assistance to facilities that are designated as "small business stationary source" as defined in the Federal Clean Air Act (42 U.S.C. Sect. 507 (c)).

However, the facility is still responsible for submitting the emission and facility data needed for the modeling analyses. Nothing in this section precludes a facility from conducting its own modeling if desired by the facility.

C. Changes in the following parameters will require a review by the facility to determine if they have an adverse impact on the compliance demonstration:

(1) Decrease in stack height
(2) Decrease in stack exit temperature
(3) Increase in stack diameter
(4) Decrease in stack exit velocity
(5) Increase in building height or building additions at the facility
(6) Increase in emission rates
(7) Decrease in distance between stack and property line
(8) Changes in stack orientation from vertical
(9) Installation of a rain cap that impedes vertical flow

Exemptions to this requirement may be granted on a case-by-case basis. A revised compliance demonstration will not be required when air dispersion modeling software programs are updated.

D. The air toxics, emission rates, and other information used in the compliance determination will be listed in Attachment A -- Modeling Parameters Used in Compliance Determination of the construction and/or operating permit for the facility. Changes that increase maximum modeled concentrations may be administratively incorporated in these permits provided a compliance demonstration using these changes is submitted to the Department. Variations from the input parameters shall not constitute a violation unless the maximum allowable ambient concentrations identified in this standard are exceeded.

E. The allowable ambient air concentrations of a toxic air pollutant beyond the plant property line as determined by modeling under Part A shall be limited to the value listed in the following table. The pollutants are divided into three categories based on chronic exposure as follows: Category 1: Low Toxicity - Those pollutants which cause readily reversible changes which disappear after exposure ends. Category 2: Moderate Toxicity - Those pollutants which may cause chronic reversible or irreversible changes that are not severe enough to result in death or permanent injury. Category 3: High Toxicity - Those pollutants which may cause chronic effects that result in death or permanent injury after very short exposure to small quantities.

CHEMICAL NAME	CAS NO.	CATEGORY	MAXIMUM ALLOWABLE CONCENTRATION

			(? g/m³) ug/m³
Acetaldehyde	75-07-0	2	1800.00
Acetamide	60-35-5	3	+
Acetic Anhydride	108-24-7	1	500.00
Acetonitrile	75-05-8	1	1750.00
Acetophenone	98-86-2	3	+
2-Acetylaminofluorne	53-96-3	3	+
Acrolein	107-02-8	3	1.25
Acrylamide	79-06-1	2	0.30
Acrylic Acid	79-10-7	3	147.50
Acrylonitrile	107-13-1	3	22.50
Aldicarb	116-06-3	2	6.00
Allyl Chloride	107-05-1	2	30.00
p-Aminodiphenyl (4-Aminobiphenyl)	92-67-1	3	0.00
Ammonium Chloride	12125-02-9	1	250.00
Aniline	62-53-3	3	50.00
o-Anisidine	90-04-0	3	2.50
p-Anisidine	104-94-9	3	2.50
Antimony Compounds	>	1	2.50
Arsenic Pentoxide	1303-28-2	3	1.00
Arsenic	7440-38-2	3	1.00
Benzene	71-43-2	3	150.00
Benzidine	92-87-5	3	0.00
Benzotrichloride	98-07-7	3	300.00
Benzyl Chloride	100-44-7	3	25.00
Beryllium Oxide	1304-56-9	3	0.01
Beryllium Sulfate	13510-49-1	3	0.01
Beryllium	7440-41-7	3	0.01
Biphenyl	92-52-4	3	6.00
Bis(Chloromethyl) Ether	542-88-1	3	0.03
Bis(2-ethylhexyl)phthalate (DEHP)	117-81-7	3	25.00
Bromoform	75-25-2	3	25.85
1,3-Butadiene	106-99-0	3	110.50
1-Butanethiol (n-Butyl Mercaptan)	109-79-5	2	15.00
n-Butylamine	109-73-9	3	75.00
Cadmium Oxide	1306-19-0	3	0.25
Cadmium Sulfate	10124-36-4	3	0.20
Cadmium	7440-43-9	3	0.25
Calcium Cyanamide	156-62-7	3	2.50
Caprolactam, vapor	105-60-2	1	500.00
Caprolactam, dust	105-60-2	1	25.00
Captan	133-06-2	3	25.00

Carbaryl	63-25-2	3	25.00
Carbon Disulfide	75-15-0	3	150.00
Carbon Tetrachloride	56-23-5	3	150.00
Carbonyl Sulfide	463-58-1	3	12250.00
Catechol	120-80-9	3	297.00
Chloramben	133-90-4	3	+
Chlordane	57-74-9	3	2.50
Chlorine	7782-50-5	1	75.00
Chloroacetic Acid	79-11-8	3	900.00
2-Chloroacetophenone	532-27-4	1	7.50
Chlorobenzene	108-90-7	3	1725.00
Chlorobenzilate	510-15-6	3	+
Chloroform	67-66-3	3	250.00
Chloromethyl Methyl Ether	107-30-2	3	+
p-Chloronitrobenzene	100-00-5	3	5.00
Chloroprene	126-99-8	3	175.00
Chromium(+6) Compounds	>	3	2.50
Cobalt Compounds	>	3	0.25
Coke Oven Emissions	>	3	+
Cresols/cresylic acid and mixture	1319-77-3	3	220.00
m-Cresol	108-39-4	3	110.50
o-Cresol	95-48-7	3	110.50
p-Cresol	106-44-5	3	110.50
Cumene	98-82-8	2	9.00#
Cyanamide	420-04-2	1	50.00
Cyanic Acid	420-05-3	1	500.00
Cyanide	57-12-5	1	125.00
Cyanide compounds[1]	>	1	+
Cyanoacetamide	107-91-5	1	125.00
Cyanogen	460-19-5	1	500.00
2,4-D,salts and esters	94-75-7	3	50.00
DDE	3547-04-4	3	+
Diazomethane	334-88-3	3	2.00
Dibenzofuran	132-64-9	3	+
1,2-Dibromo-3-chloropropane	96-12-8	3	0.05
Dibutylphthalate	84-74-2	3	25.00
p-Dichlorobenzene	106-46-7	2	4500.00
3,3 -Dichlorobenzidine	91-94-1	3	0.15
1,3-Dichloropropene	542-75-6	3	20.00#
Dichlorvos	62-73-7	3	4.52
Diethanolamine	111-42-2	2	129.00
n,n-Diethylaniline (n,n-Dimethylaniline)	121-69-7	2	250.00
Diethyl Phthalate	84-66-2	3	25.00
Diethyl Sulfate	64-67-5	3	+

Diisodecyl Phthalate	2671-40-0	2	50.00
3,3-Dimethoxybenzidine	119-90-4	3	0.30
3,3'-Dimethyl Benzidine	119-93-7	3	+
Dimethyl Carbamoyl Chloride	79-44-7	3	+
Dimethyl Formamide	68-12-2	2	300.00
1,1-Dimethyl Hydrazine	57-14-7	3	5.00
1,2-Dimethyl Hydrazine	540-73-8	3	5.00
Dimethyl Phthalate	131-11-3	3	25.00
Dimethyl Sulfate	77-78-1	3	2.50
4-Dimethylaminoazobenzene	60-11-7	3	125.00
m-Dinitrobenzene	99-65-0	2	10.00
4,6-Dinitro-o-cresol and salts	534-52-1	2	2.00
2,4-Dinitrophenol	51-28-5	3	+
2,4-Dinitrotoluene	121-14-2	3	1.50
Dioctyl Phthalate	117-84-0	2	50.00
1,4-Dioxane	123-91-1	3	450.00
1,2-Diphenylhydrazine	122-66-7	3	+
Epichlorohydrin	106-89-8	3	50.00
1,2-Epoxybutane	106-88-7	3	+
Ethanethiol	75-08-1	2	10.00
Ethanolamine	141-43-5	1	200.00
Ethyl Acrylate	140-88-5	3	102.50
Ethyl Benzene	100-41-4	2	4350.00
Ethyl Chloride	75-00-3	2	26400.00
Ethylene Dibromide	106-93-4	2	770.00
Ethylene Dichloride	107-06-2	3	200.00
Ethylene Glycol	107-21-1	3	650.00
Ethylene Oxide	75-21-8	3	10.00
Ethylene Thiourea	96-45-7	3	+
Ethylene Imine	151-56-4	3	5.00
Ethylidene Dichloride	75-34-3	3	2025.00
Formaldehyde	50-00-0	2	15.00
Formamide	75-12-7	1	750.00
Formic Acid	64-18-6	1	225.00
Furfural	98-01-1	1	200.00
Furfuryl Alcohol	98-00-0	2	400.00
Glycidaldehyde	765-34-4	3	75.00
Glycol Ethers[2] (mono- and di- ethers of diethylene glycol or triethylene glycol)	>	1	+
Glycol Ethers[2] (mono- and di- ethers of ethylene glycol)	>	3	+
Heptachlor	76-44-8	3	2.50
Hexachlorobenzene	118-74-1	3	+
Hexachlorobutadiene	87-68-3	3	1.20

Estimated Annual Average Ambient Concentrations (µg/m³) for Formaldehyde (includes secondarily formed formaldehyde)

County	FIPS	Urban or Rural	Percentile Distribution of Ambient Concentrations Across Census Tracts								Contribution to Average from ...				
			5th	10th	25th	Median	Average	75th	90th	95th	Major	Area and Other	Onroad Mobile	Nonroad Mobile	Estim Backgr
Williamsburg	45089	R	4.82E-01	4.89E-01	4.96E-01	5.02E-01	6.14E-01	5.57E-01	1.05E+00	1.53E+00	1.04E-02	2.37E-01	6.35E-02	5.29E-02	2.
York	45091	U	6.78E-01	7.65E-01	8.31E-01	9.84E-01	1.07E+00	1.10E+00	1.24E+00	1.48E+00	1.43E-01	1.96E-01	2.61E-01	2.16E-01	2.
All Urban Counties	N/A	U	5.84E-01	6.38E-01	7.26E-01	8.69E-01	8.88E-01	1.00E+00	1.13E+00	1.21E+00	2.35E-02	1.84E-01	2.73E-01	1.57E-01	2.
All Rural Counties	N/A	R	4.69E-01	4.85E-01	5.16E-01	5.74E-01	6.28E-01	6.66E-01	8.84E-01	9.58E-01	1.76E-02	1.95E-01	1.05E-01	6.04E-02	2.
Statewide	N/A	N/A	4.86E-01	5.12E-01	5.87E-01	7.46E-01	7.87E-01	9.47E-01	1.08E+00	1.17E+00	2.12E-02	1.88E-01	2.08E-01	1.19E-01	2.
Aurora	46003	R	2.64E-01	2.64E-01	2.64E-01	2.65E-01	2.65E-01	2.65E-01	2.65E-01	2.65E-01	0.00E+00	1.97E-03	7.37E-03	5.59E-03	2.
Beadle	46005	U	2.65E-01	2.65E-01	2.66E-01	2.98E-01	2.95E-01	3.07E-01	3.38E-01	3.38E-01	0.00E+00	3.22E-03	2.10E-02	2.12E-02	2.
Bennett	46007	R	2.60E-01	2.60E-01	2.60E-01	2.60E-01	2.60E-01	2.60E-01	2.60E-01	2.60E-01	0.00E+00	4.34E-03	3.73E-03	2.05E-03	2.
Bon Homme	46009	R	2.85E-01	2.85E-01	2.85E-01	2.88E-01	2.88E-01	2.90E-01	2.90E-01	2.90E-01	1.40E-05	1.14E-02	1.61E-02	9.97E-03	2.
Brookings	46011	U	2.82E-01	2.82E-01	2.82E-01	3.26E-01	3.28E-01	3.73E-01	3.76E-01	3.76E-01	1.46E-05	1.41E-02	3.71E-02	2.65E-02	2.
Brown	46013	U	2.75E-01	2.75E-01	2.81E-01	3.56E-01	3.57E-01	4.24E-01	4.53E-01	4.53E-01	0.00E+00	3.25E-02	3.62E-02	3.83E-02	2.
Brule	46015	R	2.62E-01	2.62E-01	2.62E-01	2.78E-01	2.78E-01	2.94E-01	2.94E-01	2.94E-01	0.00E+00	1.06E-02	1.05E-02	7.19E-03	2.
Buffalo	46017	R	2.64E-01	2.64E-01	2.64E-01	2.64E-01	2.64E-01	2.64E-01	2.64E-01	2.64E-01	0.00E+00	3.23E-03	5.88E-03	4.73E-03	2.
Butte	46019	U	2.59E-01	2.59E-01	2.59E-01	2.96E-01	2.96E-01	3.33E-01	3.33E-01	3.33E-01	1.33E-06	3.43E-02	7.08E-03	4.78E-03	2.
Campbell	46021	R	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	0.00E+00	6.48E-04	3.00E-03	3.28E-03	2.
Charles Mix	46023	R	2.68E-01	2.68E-01	2.68E-01	2.70E-01	2.72E-01	2.77E-01	2.77E-01	2.77E-01	4.15E-06	4.58E-03	1.04E-02	6.92E-03	2.
Clark	46025	R	2.64E-01	2.64E-01	2.64E-01	2.65E-01	2.65E-01	2.66E-01	2.66E-01	2.66E-01	0.00E+00	2.43E-03	6.59E-03	5.79E-03	2.
Clay	46027	U	2.91E-01	2.91E-01	2.91E-01	3.75E-01	3.51E-01	3.86E-01	3.86E-01	3.86E-01	0.00E+00	2.98E-02	4.46E-02	2.62E-02	2.
Codington	46029	U	2.87E-01	2.87E-01	2.88E-01	3.38E-01	3.36E-01	3.63E-01	4.02E-01	4.02E-01	0.00E+00	2.87E-02	2.80E-02	2.90E-02	2.
Corson	46031	R	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	0.00E+00	4.83E-03	2.42E-03	2.20E-03	2.
Custer	46033	R	4.62E-01	4.62E-01	4.62E-01	9.76E-01	9.76E-01	1.49E+00	1.49E+00	1.49E+00	1.12E-03	7.05E-01	1.43E-02	5.65E-03	2.
Davison	46035	U	2.71E-01	2.71E-01	2.93E-01	3.20E-01	3.12E-01	3.30E-01	3.35E-01	3.35E-01	0.00E+00	2.11E-02	2.05E-02	1.99E-02	2.
Day	46037	R	2.66E-01	2.66E-01	2.66E-01	2.68E-01	2.74E-01	2.88E-01	2.88E-01	2.88E-01	0.00E+00	3.46E-03	1.15E-02	8.96E-03	2.
Deuel	46039	R	2.78E-01	2.78E-01	2.78E-01	2.86E-01	2.86E-01	2.94E-01	2.94E-01	2.94E-01	1.25E-06	8.19E-03	1.34E-02	1.44E-02	2.
Dewey	46041	R	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	0.00E+00	6.47E-04	3.37E-03	3.21E-03	2.
Douglas	46043	R	2.67E-01	2.67E-01	2.67E-01	2.67E-01	2.67E-01	2.67E-01	2.67E-01	2.67E-01	0.00E+00	1.49E-03	9.25E-03	5.91E-03	2.
Edmunds	46045	R	2.62E-01	2.62E-01	2.62E-01	2.63E-01	2.63E-01	2.65E-01	2.65E-01	2.65E-01	0.00E+00	3.92E-03	4.74E-03	4.58E-03	2.
Fall River	46047	U	2.67E-01	2.67E-01	2.67E-01	3.35E-01	3.35E-01	4.02E-01	4.02E-01	4.02E-01	0.00E+00	7.37E-02	7.85E-03	3.12E-03	2.
Faulk	46049	R	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	2.59E-01	0.00E+00	2.35E-03	3.27E-03	3.20E-03	2.
Grant	46051	R	2.72E-01	2.72E-01	2.72E-01	2.78E-01	2.78E-01	2.83E-01	2.83E-01	2.83E-01	4.58E-07	6.82E-03	1.15E-02	9.20E-03	2.
Gregory	46053	R	2.66E-01	2.66E-01	2.66E-01	2.68E-01	2.68E-01	2.71E-01	2.71E-01	2.71E-01	0.00E+00	7.83E-03	5.98E-03	4.32E-03	2.
Haakon	46055	R	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	0.00E+00	1.54E-03	1.68E-03	1.42E-03	2
Hamlin	46057	R	2.74E-01	2.74E-01	2.74E-01	2.76E-01	2.76E-01	2.78E-01	2.78E-01	2.78E-01	3.65E-06	4.85E-03	1.15E-02	9.24E-03	2
Hand	46059	R	2.72E-01	2.72E-01	2.72E-01	2.72E-01	2.72E-01	2.72E-01	2.72E-01	2.72E-01	0.00E+00	4.57E-03	8.27E-03	9.36E-03	2
Hanson	46061	R	2.74E-01	2.74E-01	2.74E-01	2.74E-01	2.74E-01	2.74E-01	2.74E-01	2.74E-01	0.00E+00	4.27E-03	1.10E-02	8.44E-03	2
Harding	46063	R	2.51E-01	2.51E-01	2.51E-01	2.51E-01	2.51E-01	2.51E-01	2.51E-01	2.51E-01	0.00E+00	4.85E-04	5.38E-04	4.22E-04	2
Hughes	46065	U	2.66E-01	2.66E-01	3.08E-01	3.51E-01	3.32E-01	3.56E-01	3.60E-01	3.60E-01	0.00E+00	3.28E-02	2.14E-02	2.78E-02	2
Hutchinson	46067	R	2.74E-01	2.74E-01	2.74E-01	2.76E-01	2.76E-01	2.77E-01	2.77E-01	2.77E-01	3.10E-06	4.02E-03	1.32E-02	8.44E-03	2
Hyde	46069	R	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	2.57E-01	0.00E+00	1.19E-03	2.81E-03	3.21E-03	2
Jackson	46071	R	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	0.00E+00	3.33E-03	2.72E-03	1.82E-03	2
Jerauld	46073	R	2.80E-01	2.80E-01	2.80E-01	2.81E-01	2.81E-01	2.81E-01	2.81E-01	2.81E-01	0.00E+00	2.28E-03	1.32E-02	1.50E-02	2
Jones	46075	R	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	2.55E-01	0.00E+00	2.67E-03	1.54E-03	1.12E-03	2
Kingsbury	46077	R	2.66E-01	2.66E-01	2.66E-01	2.68E-01	2.68E-01	2.70E-01	2.70E-01	2.70E-01	2.53E-06	2.23E-03	8.87E-03	7.09E-03	2
Lake	46079	U	2.80E-01	2.80E-01	2.80E-01	2.94E-01	2.94E-01	3.09E-01	3.09E-01	3.09E-01	2.39E-06	5.48E-03	2.26E-02	1.62E-02	2
Lawrence	46081	U	3.88E-01	3.88E-01	4.54E-01	5.36E-01	6.37E-01	8.78E-01	9.28E-01	9.28E-01	1.03E-03	3.05E-01	3.25E-02	4.85E-02	2
Lincoln	46083	R	3.15E-01	3.15E-01	3.16E-01	3.24E-01	3.31E-01	3.46E-01	3.62E-01	3.62E-01	0.00E+00	7.05E-03	4.54E-02	2.87E-02	2
Lyman	46085	R	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	2.58E-01	0.00E+00	2.05E-03	2.74E-03	2.93E-03	2
McCook	46087	R	2.85E-01	2.85E-01	2.85E-01	2.86E-01	2.86E-01	2.87E-01	2.87E-01	2.87E-01	0.00E+00	4.86E-03	1.88E-02	1.22E-02	2
McPherson	46089	R	2.61E-01	2.61E-01	2.61E-01	2.61E-01	2.61E-01	2.61E-01	2.61E-01	2.61E-01	0.00E+00	2.71E-03	4.25E-03	3.89E-03	2
Marshall	46091	R	2.70E-01	2.70E-01	2.70E-01	2.72E-01	2.72E-01	2.73E-01	2.73E-01	2.73E-01	0.00E+00	5.87E-03	8.21E-03	7.74E-03	2
Meade	46093	R	2.75E-01	2.75E-01	3.17E-01	3.63E-01	3.45E-01	3.72E-01	3.76E-01	3.76E-01	4.99E-03	4.71E-02	3.03E-02	1.21E-02	2

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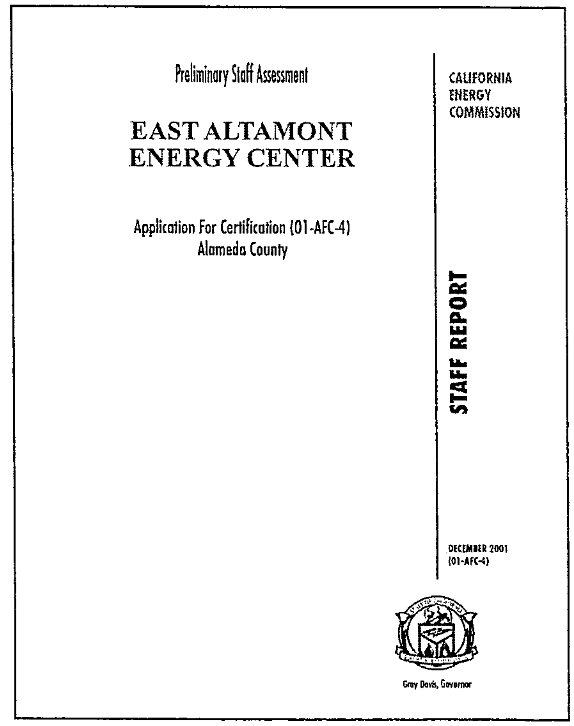
-rce: EPA POLLUTANT DATA TABLES

www.epa.gov/ttn/atw/nata/pdf/43502.f

EXHIBIT 10

California Energy Commission
Preliminary Staff Assessment, East Altamont Energy Center
December 2001, Executive Summary


Preliminary Staff Assessment

EAST ALTAMONT
ENERGY CENTER

Application For Certification (01-AFC-4)
Alameda County

CALIFORNIA
ENERGY
COMMISSION

STAFF REPORT

DECEMBER 2001
(01-AFC-4)

Gray Davis, Governor

CALIFORNIA ENERGY COMMISSION

SITING OFFICE

Cheri Davis
Project Manager

Roger E. Johnson
Office Manager

SYSTEMS ASSESSMENT & FACILITIES SITING DIVISION

Robert L. Therkelsen
Deputy Director

EXECUTIVE SUMMARY

INTRODUCTION

This Preliminary Staff Assessment (PSA)/Preliminary Environmental Assessment (EA) contains the California Energy Commission and Western Area Power Administration (Western) staff's independent analyses and recommendations on the East Altamont Energy Center (EAEC).

The EAEC and related facilities such as the electric transmission lines, natural gas line, water supply lines and wastewater lines are under the Energy Commission's jurisdiction (Pub. Resources Code § 25500). When issuing a license, the Energy Commission acts as lead state agency (Pub. Resource Code § 25519(c)) under the California Environmental Quality Act (Pub. Resource Code §§ 21000 et seq.), and its process is functionally equivalent to the preparation of an environmental impact report (Cal. Code Regs., tit. 14 § 15251(k)).

It is the responsibility of the Energy Commission staff to complete an independent assessment of the project's potential effects on the environment, the public's health and safety, and determine whether the project conforms with all applicable laws, ordinances, regulations and standards (LORS). The staff also recommends measures to mitigate potential significant adverse environmental impacts and conditions for the construction, operation, and eventual closure of the project, if approved by the Energy Commission.

The project is also under the jurisdiction of Western, as the power plant will interconnect with Western's transmission system. Western is a Federal power marketing agency under the U.S. Department of Energy that operates and maintains about 800 miles of high-voltage transmission lines and associated facilities in Northern California, including the Tracy Substation. Western's mission is to market power from federal hydroelectric plants such as those at Shasta and Folsom dams.

Federal law requires Western to provide entities, such as merchant power plants, open access to transmission services so that they can move power to load areas. Western provides these services through an interconnection if there is available capacity on the transmission line. Western is the lead federal agency for the project.

To streamline the process and eliminate overlap and duplication between the state and federal processes, this joint Energy Commission/Western PSA/Preliminary EA contains the evaluation of the project by the staffs of the California Energy Commission and Western. This document will be the basis for the decisions of both the Energy Commission and Western. This analysis includes both the construction and operation of the proposed facility. The analyses contained in this PSA/Preliminary EA were prepared in accordance with PRC Sections 25500 *et seq.*; the California Code of Regulations (CCR) Title 20, Sections 12001 *et seq.*; the California Environmental Quality Act (PRC §§ 21000 *et seq.*) and its guidelines (CCR title 14 §§ 15000 *et seq.*); the National Environmental Policy Act (NEPA) (42 U.S.C. 4371 *et seq.*) and its implementing regulations (40 C.F.R. §§ 1500 *et seq.*); and the Department of Energy

This PSA is not the decision document for these proceedings. It is preliminary in nature and represents preliminary conclusions at the staff level only. With respect to the California Energy Commission's process, it is also important to note that the final decision will be made by the Commissioners of the California Energy Commission only after the completion of the Final Staff Assessment (FSA) and evidentiary hearings. The Commissioners will consider the recommendations of all interested parties, including those of the Energy Commission staff; the applicant; intervenors; concerned citizens; and local, state, and federal agencies, before making a final decision on the application to construct and operate the EAEC.

For Western, this preliminary document serves an additional purpose. The Preliminary EA allows Western to analyze and judge the magnitude of environmental impacts and provides interested stakeholders, agencies and tribes an opportunity to review the document. If Western finds that there are no significant environmental impacts, it will issue an EA along with the California Energy Commission's FSA, and will then issue a "finding of no significant impacts" and move forward with the project. If Western determines that significant impacts are a possibility it will prepare a draft environmental impact statement instead of an EA, which entails taking a more detailed look at the impacts and alternative approaches to the project. If an EIS is needed, Western will independently publish a final environmental impact statement and Record of Decision.

PROJECT LOCATION AND DESCRIPTION

On March 29, 2001, East Altamont Energy Center, LLC, a wholly owned subsidiary of Calpine Corporation, filed an AFC with the Energy Commission for a nominal 1,100 MW power plant called the East Altamont Energy Center (EAEC). East Altamont Energy Center, LLC (applicant) proposes to construct and operate a natural-gas-fired combined-cycle generating facility with a 230-kilovolt (kV) switchyard and approximately 0.5 miles of new 230-kW transmission lines. The applicant's proposed site lies within a 174-acre parcel of land under the applicant's control, located in unincorporated Alameda County, approximately 1 mile west of the San Joaquin County line and 1 mile southeast of the Contra Costa County line. The site is bordered by Byron Bethany Road to the north, Kelso Road to the south, and Mountain House Road to the west. If built, the plant would occupy up to 40 acres near the center of the property, with the remainder available for lease as agricultural land. **PROJECT DESCRIPTION Figure 1** depicts the regional setting of the property.

The switchyard would function as an extension of Western's existing Tracy substation, located across Mountain House Road and immediately to the west of the project's site. Natural gas for the facility would be delivered via approximately 1.4 miles of new 20-inch pipeline that will connect to Pacific Gas and Electric's (PG&E) existing gas transmission line southeast of the Bethany gas compressor station located to the west of the site.

The applicant plans to supply the plant's cooling and process water requirements (roughly 4,600 acre-feet per year) with raw (i.e. untreated) water from the Byron Bethany Irrigation District, via a 2.1-mile pipeline. The applicant also indicated in their AFC that, as the community of Mountain House is developed and recycled water becomes available, the Byron Bethany Irrigation District (BBID) would be able to serve the facility in part with recycled water, resulting in a reduction in raw water use. However, because significant amounts of recycled water would not be available for at least 20 years, this identified alternative source of cooling water is considered too speculative for the purposes of the Energy Commission's analysis of the AFC. Therefore, staff's analysis assumes that the plant would rely solely on raw water.

The project as proposed includes a zero-liquid discharge system designed to eliminate off-site disposal of wastewater. Process wastewater would be reclaimed and reused, to the extent possible. Cooling water would be cycled three to eight times (depending on water quality) in the cooling tower; wastewater would then be directed to a brine crystallizer. Sanitary wastewater from sinks and toilets would be discharged to an onsite septic tank and leach field.

Associated equipment would include emission control systems necessary to meet the proposed emission limits. NOx emissions will be controlled using a combination of low NOx combustors in the combustion turbine generators (CTGs) and selective catalytic reduction systems in the heat recovery steam generators (HRSGs). A carbon monoxide catalyst would be installed in the HRSGs to limit CO emissions from the CTGs.

The project is estimated to have a capital cost of between $400 and $500 million. The applicant plans to begin construction in June 2002 and complete construction in June 2004. The project would result in a peak of approximately 400 construction jobs over a 2-year period and up to 40 skilled operational positions throughout the life of the project.

PUBLIC AND AGENCY COORDINATION

In preparing the PSA, Energy Commission and Western staff conducted several publicly noticed joint workshops. These workshops were invaluable for bringing out comments of concerned citizens. Staff also has coordinated with relevant local, state and federal agencies, such as the California Independent System Operator (Cal-ISO), Bay Area Air Quality Management District, U.S. Fish and Wildlife Service, California Department of Fish and Game, and the Central Valley Regional Water Quality Control Board.

Written comments received from members of the public, and letters from agencies that require some form of response, have been included in this PSA. No comments have been received from intervenors.

STAFF'S ASSESSMENT

Each technical area section of the PSA contains a discussion of impacts, and where appropriate, mitigation measures and conditions of certification. The PSA includes staff's assessments of:

- the environmental setting of the proposal;
- impacts on public health and safety, and measures proposed to mitigate these impacts;

- environmental impacts, and measures proposed to mitigate these impacts;
- the engineering design of the proposed facility, and engineering measures proposed to ensure the project can be constructed and operated safely and reliably;
- project closure;
- project alternatives;
- compliance of the project with all applicable laws, ordinances, regulations and standards (LORS) during construction and operation; and
- proposed conditions of certification.

OVERVIEW OF STAFF'S CONCLUSIONS

Environmental / System Impacts and LORS

Staff's analysis indicates that the project's environmental impacts can be mitigated to levels of less than significant in all areas except for Air Quality, Biological Resources, Land Use, Visual Resources, Soil and Water Resources, and Transmission System Engineering. Staff's analysis also indicates that the project can be made to conform with all LORS except in the areas of Air Quality, Land Use, Soil and Water Resources, and Transmission System Engineering. Below is a summary of the potential environmental impacts and LORS compliance for each technical area.

Technical Discipline	Environmental / System Impact	LORS Conformance
Air Quality	Staff cannot conclude	Staff cannot conclude
Biological Resources	Staff cannot conclude	yes
Cultural Resources	Impacts mitigated	yes
Power Plant Efficiency	N/A	N/A
Power Plant Reliability	N/A	N/A
Facility Design	N/A	yes
Geology	Impacts mitigated	yes
Hazardous Materials	Impacts mitigated	yes
Land Use	Staff cannot conclude	Staff cannot conclude
Noise	Impacts mitigated	yes
Public Health	Impacts mitigated	yes
Socioeconomics	Impacts mitigated	yes
Traffic and Transportation	Impacts mitigated	yes
Transmission Line Safety	Impacts mitigated	yes
Transmission System Engineering	Staff cannot conclude	Staff cannot conclude
Visual Resources	Staff cannot conclude	yes
Waste Management	Impacts mitigated	yes
Water and Soils	Staff cannot conclude	Staff cannot conclude
Worker Safety	Impacts mitigated	Yes

The following summarizes staff's position with respect to the technical areas listed as "Staff cannot conclude":

Air Quality

There are still a number of significant, outstanding air quality issues that have the potential to delay the overall project schedule and have impacted staff's ability to draw conclusions in the PSA.

- First and foremost, the Bay Area Air Quality Control District has not issued its Preliminary Determination of Compliance for the project. Without the PDOC, staff cannot conclude that the project would be in conformance with local, state, and federal air quality laws.
- Still unresolved at this time is the matter of what Best Available Control Technology should apply to the EAEC. The applicant has proposed to use selective catalyst reduction (SCR) and oxidation catalysts to minimize the emissions of oxides of nitrogen (NOx) to 2.5 parts per million (ppm), and carbon monoxide (CO) to 6 ppm, while maintaining the slip of ammonia (NH3) emissions to 10 ppm. However, the Federal Environmental Protection Agency (EPA), recently determined that the BACT for a combustion turbine combined cycle operation should be set at 2 ppm for NOx, 2 ppm for CO and 5 ppm for ammonia. Staff is recommending that the project mitigate to the above-mentioned EPA-recommended BACT levels, but the EPA will not officially comment on this project until after the PDOC.
- Staff has found that the project's emissions of NO_x and VOC have the potential to cause significant impacts relative to the state 1-hour and the federal 8-hour ozone air quality standards. The area experiences violations of the state 1-hour and federal 8-hour ozone standards each year (since 1992) and there is no clear indication of improvement. Thus, it is crucial that any NO_x and VOC emission increases be fully offset to avoid worsening violations of the ozone ambient air quality standard. The applicant has not provided staff with enough information about the emission reduction credits (ERCs), and staff therefore cannot determine whether the applicant's proposed offset package is adequate to mitigate the project's emissions of NO_x and VOC to a level of less than significant.
- Staff has found that the project has the potential to cause significant impacts relative to the state 24-hour PM_{10} and the federal 24-hour $PM_{2.5}$ air quality standards. Staff finds that the proposed ERCs, however, are not adequate to mitigate the project's emissions of PM_{10} and $PM_{2.5}$. Staff understands that the applicant is in the process of changing their mitigation proposal, but until staff receives the revised proposal and evidence of ERCs, staff cannot draw any conclusions about the project's mitigation for PM_{10} and $PM_{2.5}$.
- Staff continues to disagree with the applicant over emission levels and mitigation for PM_{10}, NO_2, VOC, and SO_2, and the level of detail that must be provided to staff regarding key pieces of equipment. The applicant maintains that the design is not finalized, thus specific information about the duct burners (which are significantly larger than the duct burners seen in other California power plants), the boiler, and the emergency generator and fire pump are not available. Because emission data and physical characteristics of the equipment involved have not been provided, staff cannot verify the modeling analysis performed by the applicant, and lacks the information required to properly assess the project's impacts. Further, the applicant has not yet provided enough information for staff to evaluate the ERCs for this

project. Staff cannot complete its analysis until the applicant provides more information in these areas. Staff plans to issue new data requests that clarify the information that we require.

- Finally, staff has requested the applicant prepare a cumulative impacts analysis that includes the Tracy Peaker Project, the Tesla Power Project, and the build-out of the new community of Mountain House. Until this analysis is completed, staff cannot reach conclusions regarding cumulative impacts to air quality.

Visual Resources

It is staff's conclusion that the proposed power plant facility is inconsistent with the existing rural character of the area. It would be visible from recreational areas and would affect panoramic scenic views. The applicant's proposed visual resources mitigation measures and screening plan, and staff's proposed mitigation measures and conditions of certification would mitigate the visual impacts of the proposed project to less than significant levels. However, biology staff of the Energy Commission, California Department of Fish and Game (CDFG) and U.S. Fish and Wildlife Service (USFWS) are concerned about potential biological impacts of the proposed landscaping. To address this issue, the applicant has prepared a revised landscaping plan that staff will evaluate in the Final Staff Assessment. If the revised landscape plan would not result in full and timely implementation of staff's proposed landscaping mitigation, or if the mitigation is determined to not be feasible, significant visual impacts from the proposed project structures would remain.

Biological Resources

The following represent outstanding issues for Biological Resources:

- Staff is concerned about the timing of the Section 7 consultation process. The Biological Assessment has not been submitted by the applicant to Western, and thus the Section 7 consultation with the USFWS has not yet been initiated. Delays in the Section 7 consultation process could significantly affect the overall project schedule. Staff cannot draw conclusions about the project's potential for environmental impacts until it has the final Biological Opinion, or a draft of the Biological Opinion that provides reasonable assurance of the mitigation that will be included in the Biological Opinion.

- At present, the requirement that the applicant avoid adverse biological impacts from the proposed landscaping conflicts directly with mitigation required to minimize impacts to visual resources. Because the proposed landscaping would provide perching opportunities for raptors, and may harm federally listed species, biology staff, CDFG, and USFWS believe that the originally proposed landscaping is unacceptable. The most recent landscaping proposal continues to be reviewed and discussed among the agencies, the applicant, and staff. Staff needs to receive further information from the applicant on the habitat mitigation and will consult with USFWS and CDFG in order to ensure that the mitigation determined in the FSA is sufficient.

- The EAEC proposes to use fresh water for cooling. This water would be delivered by the BBID, which removes water from the California Aqueduct, and ultimately, the Sacramento San Joaquin Delta (Delta). The Delta is critical habitat for many declining or endangered fish species, and also supports fish of importance to sport fishermen.

- Staff is concerned with the levels of water to be withdrawn from the Delta due to the indirect and cumulative impacts this would have on native listed fish populations and their habitats. The National Marine Fisheries Service (NMFS) has expressed concern for the potential of indirect ecological impacts of water diversions from the Delta, which is designated as critical habitat for these fish species. The NMFS stated: "If diversions are not increased over current conditions, we would not anticipate adverse effects on listed salmon or steelhead, designated critical habitat or Essential Fish Habitat (EFH). *However, if diversions into the California Aqueduct are increased as a result of the construction and operation of the proposed project,* adverse effects on listed salmon or steelhead, designated critical habitat, and/or EFH may occur, and further consultation would be required." (emphasis added) (NMFS 2001).

  The EAEC will require approximately 4,600 acre-feet per year of water. While Byron Bethany Irrigation District (BBID) – the water purveyor for the EAEC – maintains that serving the EAEC with this water will not result in additional water diversions to the California Aquaduct, staff has no evidence of this. Such a level of water diversion from the Delta, if it occurred, would cause potentially significant adverse impacts to listed fish populations in the Delta. DWR as well has expressed concern that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plantlife, fish and wildlife, could be injured. (CEC 2001i, page 1) Given that two other power plant applications being considered by the Energy Commission include proposals to withdraw freshwater from the Delta (i.e. the Tracy Peaker Plant and Tesla Power Plant), impacts to fish populations could be compounded and the combined water withdrawals could cause significant adverse cumulative impacts.

  The question of whether or not the proposed supply of water for the EAEC would result in increased diversions from the Delta must be resolved before a final assessment of project impacts can be completed. As noted in the **Soil and Water Resources** section of this Staff Assessment, staff is awaiting additional information from DWR and the Applicant relative to previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP. If staff determines that there could be increased diversions from the Delta, the applicant will need to consult a second time with NMFS. Until information received either confirms that there would be no net withdrawals from the Delta, or a second consultation with NMFS is completed, staff cannot conclude that there are less than significant impacts to native special status fish populations. If staff cannot confirm that there are no net withdrawals from the Delta, staff will additionally need to evaluate cumulative impacts.

Soil and Water Resources

Based on the analysis of water supply and cooling alternatives, and the apparent potential to cause adverse impacts to the environment or injury to other water users, staff cannot conclude at this time that the proposed project would not cause significant adverse impacts with regard to water supply. The proposed project could lead to significant adverse impacts as a result of relying on BBID to divert fresh water from the Delta for EAEC during seasons and in quantities uncharacteristic of BBID's historic patterns of diversion. The project as proposed, may not comply with LORS from the standpoint of the California Water Code, section 1202(b), in that the proposed season and quantities of diversion to supply EAEC may not rely entirely on BBID's entitlements for appropriated water. DWR has expressed concern that its beneficial uses under the SWP, or other Delta beneficial uses including maintenance of plantlife, fish and wildlife, could be injured. (CEC 2001i, page 1)

Staff is awaiting additional information from DWR and the Applicant regarding previous Bay-Delta analyses and the relationship of BBID's water entitlements to those of the SWP and CVP, in order to more fully evaluate the potential impacts from the proposed water supply to EAEC. In particular, staff is looking to DWR for a determination on their ability to decrease withdrawals to offset BBID's anticipated increase in withdrawals to serve the EAEC. Staff is also issuing new data requests to clarify information needed from the applicant. Staff is planning to meet with all appropriate agencies to resolve these issues, and will make every effort to have the affected agencies participate in staff workshops.

Land Use

The project site is located on land that is zoned as large parcel agricultural. If Alameda County was the lead agency for this project, the project would be required to obtain a conditional use permit, which in turn would require that the County make certain findings. Staff has requested that the County staff make these findings, which the Commission staff could evaluate and incorporate into its final analysis. Staff has not yet received these conditional use permit findings from Alameda County. Therefore, staff cannot conclude that the project will comply with LORS.

The applicant is proposing to develop a power generation facility outside of the designated Urban Growth Boundary in an agricultural area that is away from existing urban uses. The conversion of at least 40 acres from an agricultural use to a nonagricultural use (the proposed power plant), including the loss of prime agricultural land, presents potential non-conformity issues with ABAG policies and could present a significant impact under CEQA.

The applicant and the County of Alameda are negotiating a mitigation agreement involving placing the remainder of the subject property not used for the construction of the power plant into preservation and either the purchasing of off-site comparable lands or easements nearby at a one-to-one ratio of land lost or contributing to the Alameda County agricultural land preservation funds. The finalized mitigation agreement would bring the project into compliance with the ABAG Regional Goals and Policies under Preservation of Agricultural Resources. As of the writing of this PSA, staff has not received a copy of the final agricultural land conversion mitigation agreement between the applicant and the County of Alameda, and cannot conclude that CEQA impacts have been mitigated or that the project will conform to applicable LORS.

Transmission System Engineering

Staff finds that the System Impact Study (SIS) analyses, reports and filings provided by the Applicant are incomplete. Based upon current study results, staff concludes that the EAEC project has some negative impacts on the transmission system and it is unclear whether and how these would be mitigated. As outlined in the power flow study results, several transmission elements potentially exceed ratings beyond reliability criteria with the interconnection of the EAEC project under normal and contingency system conditions.

However, because the SIS reports and filings not yet complete, staff is unable to fully evaluate downstream impacts, transmission facilities, and/or mitigation measures required for reliable operation of the electrical transmission system. While it appears that information requested by staff has been provided by Western (the transmission owner and Interconnection Authority) to the applicant, staff has not received such information and therefore cannot conclude that the project will conform with all system reliability LORS. Staff plan to issue new data requests in order to clarify its data needs.

Environmental Justice

EPA guidelines on environmental justice state that if 50 percent of the population affected by a project has minority or low-income status, it must be determined if these populations are exposed to disproportionately high and adverse human health or environmental impacts.

Environmental Justice Screening Analysis

In the **Socioeconomics** section of this report, staff presents the results of their "environmental justice screening analysis." The purpose of the environmental justice screening analysis is to determine whether of not there is a low-income and/or minority population within the potential affected area of the proposed site.

Socioeconomics Figure 1 identifies census blocks within six miles of the proposed project that had minority populations greater than 50 percent. Census 2000 data indicate that the minority population within the six mile radius of the project site is 34 percent. However, there are areas that have two or more contiguous census blocks with a minority population greater than 50 percent. Staff considers these areas to be pockets of predominately minority populations, therefore various technical staff will consider environmental justice impacts in their analyses.

The percent of population considered low-income or living below the poverty level ranges from 16 percent in San Joaquin County to 7 percent in Contra Costa County. In 1990, the percentage of the population living below the poverty level was 10 percent within a six-mile radius of the EAEC. This percentage is well below the threshold of greater than 50 percent that staff uses to determine if there is a significant low-income population.

When a minority and/or low-income population is identified, as is the case for this project, staff in the technical areas of air quality, public health, hazardous materials, noise, water, waste, traffic and transportation, visual resources, land use, socioeconomics and transmission line safety and nuisance, must consider possible impacts on the minority/low-income population as part of their analysis. This "environmental justice" (EJ) analysis consists of identification of significant impacts (if any), identification of mitigation, and determination of whether there is a disproportionate impact if an unmitigated significant impact has been identified.

Environmental Justice Findings

Given that there are technical areas for which staff cannot complete their analysis, staff is unable to draw any final conclusions concerning the potential for unmitigated or disproportional adverse impacts on an EJ population.

CONCLUSION AND RECOMMENDATIONS

Summarizing the items identified above, staff cannot reach conclusions about the project's environmental or system impacts, conformance with LORS, and environmental justice, until we receive the following:

AIR QUALITY

- From the Bay Area Air Quality Management District, the PDOC and FDOC; and
- From the applicant:
  - Emissions data and other data concerning of key pieces of equipment, for the air quality analysis;
  - Evidence of ERCs for mitigation of particulate matter emissions; and
  - A complete cumulative air impacts analysis.

BIOLOGICAL RESOURCES

- A copy of the completed Biological Assessment when it is submitted to the USFWS by Western;
- The Biological Opinion from USFWS, or a draft of the Biological Opinion that provides reasonable assurance of the mitigation that will be included in the Biological Opinion;
- Further information from the applicant on habitat mitigation; and
- Written clarification from DWR on their ability to decrease withdrawals to offset BBID's anticipated increase in withdrawals to serve the EAEC and, potentially, a second consultation with NMFS.

SOIL AND WATER RESOURCES

- Written clarification from DWR on their ability to decrease withdrawals to offset BBID's anticipated increase in withdrawals to serve the EAEC; and
- The applicant's responses to water-related data requests.

LAND USE

- Conditional use permit findings from Alameda County.

TRANSMISSION SYSTEM ENGINEERING

- Completion of the System Impacts Study reports and filings, as detailed in this PSA.

Staff's goal is to resolve as many of these concerns as possible prior to release of the FSA, through PSA workshops, issue resolution workshops (to work through the more complex issues). Staff is also issuing new data requests to clarify staff's information needs. However, staff cannot predict the amount of time that will be needed for parties to provide the needed information and for agencies to issue their determinations. For that reason, staff has proposed an FSA schedule that is linked to the receipt of the critical information identified above. Taking into consideration the amount of time necessary for analysis, review, and formatting and printing of the document, staff will need at least 45 working days to complete the FSA. Therefore, staff proposes to file the FSA 45 working days after all critical pieces of information and final determinations from the relevant agencies are received.

EXHIBIT 11

News Release, Gila Bend Plant

NEWS RELEASES

TO: EDITORS, NEWS DIRECTORS **DATE:** April 4, 2001
FOR: IMMEDIATE RELEASE

Commission Approves Power Plant but Adds Tough New Emissions Requirements

PHOENIX - The Arizona Corporation Commission yesterday approved the siting of a power plant in Gila Bend. The natural gas fired combined cycle plant will generate 845 MW once completed. The plant is being developed by Gila Bend Power Partners, LLC, a joint venture of Power Development Enterprises and Industrial Power Technology. The approval came with several conditions, including one that requires the plant to meet strict environmental standards.

Commission Chairman Bill Mundell sponsored a groundbreaking amendment intended to hold the applicant to strict emission standards such as those in coastal California. After debate, the applicant agreed to meet more stringent air quality standards. The amendment approved by the Commission reads:

"Applicant shall install and operate catalytic oxidation technology that will produce a carbon monoxide emission rate equivalent to California BACT and similar collateral reductions for Volatile Organic Compounds (VOCs) and condensable particulate matter."

BACT stands for Best Available Control Technology. The purpose of BACT is to control specific emissions and limit the adverse effect of a plant's emissions on a region. BACT prescribes standards and technology required for compliance with air quality provisions.

Catalytic oxidation technology is used to remove carbon monoxide and Volatile Organic Compounds, including those which condense to form particulate matter, from the exhaust stacks. Catalytic converters on automobiles perform a similar function, though on a much smaller scale.

Gila Bend currently meets the federal air quality requirements so this additional pollution control equipment is not required to comply with federal or state standards. The Commissioners each commented, however, that the boundaries for attainment areas could shift in the future due to political, economic or environmental forces. As Chairman Mundell stated, "The plant siting statutes require the Commission to balance the need for an adequate and economical power supply with the desire to minimize the

"I am pleased that the developer agreed to install additional emission control technology as a condition of approval. This is a landmark decision for power plant sitings and I hope plant developers get the message that we want minimal impact on local or regional air quality," Chairman Mundell stated. Without such a condition, Mundell indicated that he was prepared to vote against the plant. Commissioner Marc Spitzer also voted to approve the plant with the additional conditions. Although he voted in favor of the stricter emissions requirements, Commissioner Jim Irvin voted against the plant citing his concerns with the state's transmission and gas pipeline capacity.

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EXHIBIT 12

Analysis of Strategies for Reducing the Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury, and a Renewable Portfolio Standard
Energy Information Administration, Department of Energy

1. Introduction

Over the next decade, electric power plant operators may face significant requirements to reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) beyond the levels called for in current regulations. They could also face requirements to reduce carbon dioxide (CO_2) and mercury (Hg) emissions. At present neither the future reduction requirement nor the timetable is known for any of these airborne emissions; thus, compliance planning is difficult.

Currently, different environmental issues are being addressed through separate regulatory programs, many of which are undergoing modification. To control acidification, the Clean Air Act Amendments of 1990 (CAAA90) required operators of electric power plants to reduce emissions of SO_2 and NO_x. Phase II of the SO_2 reduction program—lowering allowable SO_2 emissions to an annual national cap of 8.95 million tons—became effective on January 1, 2000.[1] More stringent NO_x emissions reductions are required under various Federal and State laws taking effect from 1997 through 2004. States are also beginning efforts to address visibility problems (regional haze) in national parks and wilderness areas throughout the country. Because electric power plant emissions of SO_2 and NO_x contribute to the formation of regional haze, States could require that these emissions be reduced to improve visibility in some areas. In the near future, it is expected that new national ambient air quality standards for ground-level ozone and fine particulates may necessitate additional reductions in NO_x and SO_2.

To reduce ozone formation, the U.S. Environmental Protection Agency (EPA) has promulgated a multi-State summer season cap on power plant NO_x emissions that will take effect in 2004. Emissions that lead to fine particles (less than 2.5 microns in diameter), their impacts on health, and the level of reductions that might be required are currently being studied. Fine particles are associated with power plant emissions of NO_x and SO_2, and further reductions in NO_x and SO_2 emissions could be required by as early as 2007 in order to reduce emissions of fine particles. In addition, the EPA decided in December 2000 that Hg emissions must be reduced; proposed regulations will be developed over the next 3 years. Further, if the United States decides that emissions of greenhouse gases need to be mitigated, it is likely that energy-related CO_2 emissions will also have to be reduced.

Because the timing and levels of emission reduction requirements under the new standards are uncertain, compliance planning is complicated. It can take several years to design, license, and construct new electric power plants and emission control equipment, which may then be in operation for 30 years or more. As a result, power plant operators must look into the future to evaluate the economics of new investment decisions. The potential for new emissions standards with different timetables adds considerable uncertainty to investment planning decisions. An option that looks attractive to meet one set of SO_2 and NO_x standards may not be attractive if further reductions are required in a few years. Similarly, economical options for reducing SO_2 and NO_x today may not be the optimal choice in the future if Hg and CO_2 emissions must also be reduced. Further complicating planning, some investments capture multiple emissions simultaneously, such as advanced flue gas desulfurization equipment that reduces SO_2 and Hg, making such investments more attractive under some circumstances. As a result, power plant owners currently are wary of making investments that may prove unwise a few years hence.

In both the previous and current Congresses, legislation has been proposed that would require simultaneous reductions of multiple emissions. Several bills were introduced in the 106th Congress to address these issues: S. 1369, the Clean Energy Act of 1999, introduced by Senator Jeffords; S. 1949, the Clean Power Plant and Modernization Act of 1999, introduced by Senator Leahy; H.R. 2900, the Clean Smokestacks Act of 1999, introduced by Congressman Waxman; H.R. 2645, the Consumer, Worker, and Environmental Protection Act of 1999, introduced by Congressman Kucinich; and H.R. 2980, the Clean Power Plant Act of 1999, introduced by Congressman Allen.[2]

Additional bills introduced in the 107th Congress with similar goals include S. 556, the Clean Power Act of 2001, introduced by Senator Jeffords; H.R. 1256, the Clean Smokestacks Act of 2001, introduced by Congressman Waxman; and H.R. 1335, the Clean Power Plant Act of 2001, introduced by Congressman Allen. Each of the bills introduced in the 106th and 107th Congresses contains provisions to reduce power plant emissions of NO_x, SO_2, CO_2, and Hg over the next decade. The bills use different approaches—traditional technology-specific emission standards, generation performance standards, explicit emission caps with trading programs, or combinations of the three—but all call for significant reductions. In addition, the Bush Administration's National Energy Policy recommends the establishment of "mandatory reduction targets for emissions of three main pollutants: sulfur dioxide, nitrogen oxides and mercury."[3] While differences exist on what the appropriate emission targets should be and how the program should be implemented, it is generally agreed that a more predictable emission reduction policy is worth pursuing.

The analysis described in this report was conducted at the request of the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform.[4] In its request the Subcommittee asked the Energy Information Administration (EIA) to "analyze the potential costs of various multi-emission strategies to reduce the air emissions from electric power plants." The Subcommittee requested that EIA examine cases with alternative NO_x, SO_2, CO_2, and Hg emission reductions, with and without a renewable portfolio standard (RPS) requiring a specified portion of all electricity sales to come from generators that use nonhydroelectric renewable fuels.

At the request of the Subcommittee, EIA prepared an initial report (referred to here as "the earlier EIA report") that focused on the impacts of reducing power sector NO_x, SO_2, and CO_2 emissions.[5] The current report extends EIA's earlier analysis to add the impacts of reducing power sector Hg emissions and introducing RPS requirements. Expected costs to the energy sector and to consumers of meeting the specified emission caps and the RPS are examined (see Chapter 2 for a discussion of the specific scenarios prepared). The potential benefits of reduced emissions—such as might be associated with reduced health care costs—are not addressed, because EIA does not have expertise in this area. The bibliography for this report includes several studies that address the benefits of reducing emissions.

The analysis presented in this report should be seen as an examination of the steps that power suppliers might take to meet the emission caps specified in the Subcommittee's request for analysis. The specific design of the cases—timing, emission cap levels, policy instruments used, etc.—is important and should be kept in mind when the results are reviewed.[6] For example, all the analysis cases assume that market participants—power suppliers, consumers, and coal, natural gas, and renewable fuel suppliers—would become aware of impending emission caps before their target dates and would begin to take action accordingly. If it had been assumed that market participants would not anticipate the emission caps, the results would be different. In an earlier EIA study that looked at alternative program start dates for imposing a CO_2 emissions cap (or carbon cap), an earlier start date and longer phase-in period were found to smooth the transition of the economy to the longer run target.[7]

This study is not intended to be an analysis of any of the specific congressional bills that have been proposed, and the impacts estimated here should not be considered as representing the consequences of specific legislative proposals. All the congressional proposals include provisions other than the emission caps and RPS requirements studied in this analysis, and several would use different policy instruments to meet the emission targets. Moreover, some of the actions projected to be taken to meet the emission caps in this analysis may eventually be required as a result of ongoing environmental programs whose requirements currently are not specified.

The purpose of this report is to respond to the Subcommittee's request; however, it also provides an important secondary benefit by establishing a framework for analysis that evolved in the research and modeling undertaken to complete the analysis.

During the course of this work, many choices had to be made about specific configurations for mercury mitigation technologies and their costs and performance characteristics; the response of fuels markets to much more stringent emission constraints; and the reaction of consumers to higher prices for electricity, coal, and natural gas. In an attempt to capture the uncertainties associated

[3]President George W. Bush, *National Energy Policy: Report of the National Energy Policy Development Group* (Washington, DC, May 2001).

[4]In the 107th Congress this subcommittee has been renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

[5]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR/OIAF/2000-05 (Washington, DC, December 2000). See also J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emission Reductions Using a Generation Performance Standard," web site www.eia.doe.gov/oiaf/servicerpt/gps/gpsstudy.html.

[6]For a discussion of one possible alternative policy instrument, see the box on "Generation Performance Standards" on page 14 of the

with these choices, this report shows a wide range of cases with alternative assumptions for many of the major inputs. It would be impossible, however, to capture the full range of possible outcomes that could result from the policies examined in this analysis. Rather, this report should be seen as an indicator of a possible set of energy market responses to multiple emission targets, providing a basic platform from which interested readers can obtain broad estimates of energy prices, supply, and demand in response to alternate sets of assumptions.

EXHIBIT 13

EPA Surface Water Discharges from the Celanese-Acetate plant located upstream of the proposed Palmetto Energy Center

ENVIROFACTS REPORT ON
CELANESE ACETATE L L C CELRIVER PLANT

2850 CHERRY RD.
ROCK HILL, SC 29730

Map this facility

Map this facility using one of Envirofact's mapping utilities.

EPA Facility Information

This query was executed on MAR-02-2002

Toxic Releases for Reporting Year 1999

ILITY ID: 29730HCHST2850C

es for 1999

ΣE	SIC CODE DESCRIPTION
	PLASTICS MATERIALS, SYNTHETIC RESINS, AND NONVULCANIZABLE ELASTOMERS
	CELLULOSIC MANMADE FIBERS
	MANMADE ORGANIC FIBERS, EXCEPT CELLULOSIC
	INDUSTRIAL ORGANIC CHEMICALS, NOT ELSEWHERE CLASSIFIED

ANE	000110543	1399130273865	24278	EMISSION FACTORS	POINT EMISSIONS
ANE	000110543	1399130273865	133868	MASS BALANCE CALCULATIONS	STACK OR POINT EMISSIONS
L	000108952	1399130273915	127	MASS BALANCE CALCULATIONS	FUGITIVE OR NON-POINT EMISSIONS
L	000108952	1399130273915	796	MASS BALANCE CALCULATIONS	STACK OR POINT EMISSIONS
OROFLUOROMETHANE	000075694	1399130273853	800	MASS BALANCE CALCULATIONS	FUGITIVE OR NON-POINT EMISSIONS
ACETATE	000108054	1399130273927	704	OTHER	FUGITIVE OR NON-POINT EMISSIONS
ACETATE	000108054	1399130273927	2932	OTHER	STACK OR POINT EMISSIONS

als Released to Surface Water

ICAL NAME	TRI CHEM ID	DOCUMENT	RELEASE AMOUNTS LBS/YR	RELEASE BASIS CODE	STORM WATER APPLICABILITY FLAG	STORM WATER PERCENTAGE
NITRILE	000075058	1399130273737	✓ 1662	MONITORING DATA	0	0
C ACID	000079107	1399130273749	X 5	OTHER	0	0
ACRYLATE	000141322	1399130273752	X 78	OTHER	0	0
INE	007782505	1399130273776	X 2822	MONITORING DATA	0	0
ACRYLATE	000140885	1399130273814	X 2	OTHER	0	0
LDEHYDE	000050000	1399130273838	✓ 8997	OTHER	0	0
C ACID	000064186	1399130273840	X 33	MASS BALANCE CALCULATIONS	0	0
NOL	000067561	1399130273889	✓ 150	OTHER	0	0
L ETHYL E	000078933	1399130273891	✓ 913	MONITORING DATA	0	0
'L ALCOHOL	000071363	1399130273764	✓ 1	OTHER	0	0
L	000108952	1399130273915	✓ 817	MASS BALANCE CALCULATIONS	0	0
ACETATE	000108054	1399130273927	X 339	OTHER	0	0

als Released via Underground Injection

as no data of this type reported for this facility.

EXHIBIT 14

Article on Theory of Insignificant Impact

Power Plant: Ratio Theory of Impact Analysis

The *ratio theory of impact analysis* is used by proponents of polluting projects to try to show the amount of pollution from a project is *insignificant*. This is done by comparing the pollution from the project to existing sources of pollution.

For example in the Mercury News' editorial on June 13, 1999 titled *In our back yard? Considering overall picture, this plant would not be an environmental threat* the Mercury News said:

> The Calpine plant would produce enough pollution to increase the total nitrogen oxide emissions in the county four-tenths of 1 percent.

In the California Environmental Quality Act (CEQA) review of the proposed sale of four Pacific Gas and Electric Company (PG&E) power plants (www.pgedivest.com), the comments from the Southeast Alliance for Environmental Justice describe the *ratio theory of impact analysis* in more detail. From www.pgedivest.com/eirtc/comments/u.html:

> A project's impact cannot be considered insignificant because it's contribution to air quality is insignificant when compared to other sources. Kings County Farm Bureau v. City of Hanford 221 Cal. App.3d 692, 720 (5th Dist. 1990). The Court of Appeals held inadequate the cumulative impact analysis prepared for an EIR for a proposed coal-fired cogeneration power plant. The Court called this method of finding an impact insignificant because it was small compared to other sources, the incorrect approach. Id. This "ratio" theory of impact analysis allows a large pollution problem to make a project's contribution appear less significant in a cumulative impact analysis. But the Court strongly disagreed, holding that such a method would "avoid analyzing the severity of the problem and allow approval of projects which, when taken in isolation, appear insignificant, but when viewed together, appear startling." It is invalid and terribly misleading of the DEIR to conclude that the impacts to air quality are insignificant because it is less then one percent of regional emissions. (Pg 4.5-59). In fact, the more severe existing environmental problems are, the lower the threshold should be for treating a project's cumulative impacts as significant. Id. at 721. See discussion of Los Angeles Unified School District v. Los Angeles (1997) 58 Cal. App. 1019, supra.

As the air quality in a region declines, new sources of pollution look less and less significant using the *ratio theory of impact analysis*.

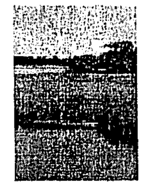
EXHIBIT 15

Map, York County SC

The General Plan, 1999 - 2009
A Comprehensive Plan for Rock Hill, South Carolina
Population, pp. 5 - 7

SCIway South Carolina's Front Door

home | partners | advertise | sc shop | add site | newsletter | site map | ask? | contact us



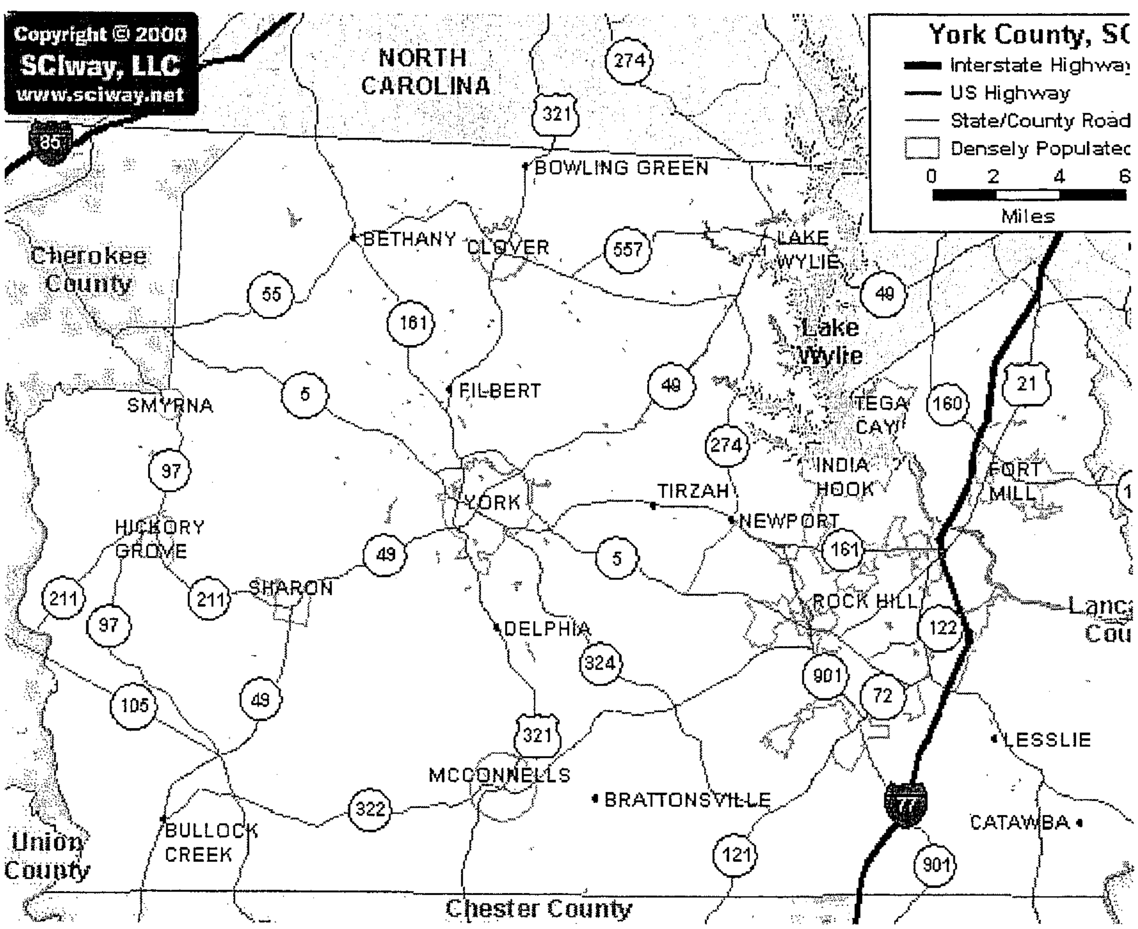
► Click to

Search S

Map of York County, South Carolina

York County Web Sites | Places in York County | Other SC County Maps | All SC Maps

► Learn more about York County



► Learn more about York County

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For more information and pricing, please write us at service@sciway.net.

Ring City	No Diploma	HS Diploma	Some College	College Degree
Concord	33.8%	27.0%	24.4%	14.8%
Gastonia	37.6%	23.8%	22.6%	16.0%
Kannapolis	41.3%	30.7%	20.3%	7.7%
Monroe	35.1%	28.1%	22.2%	14.6%
Rock Hill	37.1%	23.4%	21.8%	17.7%
Charlotte MSA	19.0%	22.7%	29.9%	28.4%

adequate opportunities for each resident is formidable task. Table 5 shows the number of resident over the age of 25 and their highest level of educational attainment.

The presence of an educated citizenry is imperative for success. Businesses emphasize time and again the importance of education in selecting sites for expansion. The absence of educated residents may serve as a wake up call to those in authority to increase funding or better manage existing resources.

Income

Income is an often-used indicator of economic prosperity. Table 6 outlines the amount of income a resident earns by household and family categories. A household is defined as those unrelated persons living in the same residence. A family is related persons living in the same residence. Household size is the median number of people per dwelling unit.

Table 6 shows the relative household and family incomes of the ring cities and the central city - Charlotte. Table 6 also relates the number of people affected by poverty. The Metro average of 9.6 percent is far below that of the ring cities.

INCOME & POVERTY
TABLE 6

Ring City	HH Inc	Family Inc	Poverty
Concord	$25,473	$32,170	12.1%
Gastonia	$25,910	$31,205	14.2%
Kannapolis	$22,369	$28,237	11.8%
Monroe	$23,153	$27,851	16.7%
Rock Hill	$26,615	$31,404	16.4%
Charlotte MSA	$31,873	$38,553	9.6%

Charlotte's higher incomes and lower poverty seem to indicate that has not been experiencing the same flight to the suburbs as other metro areas. That may change as the ring cities capture an increasing share of the growth of the region.

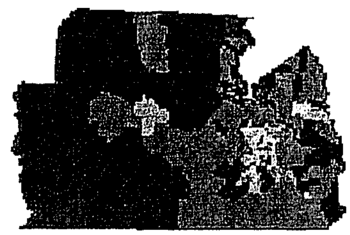
Although Rock Hill has competitive Household and family incomes, it is at the high end of the metro cities in measures of poverty level. This difference is partly due to stricter South Carolina annexation policy, which leaves Rock Hill with additional higher-income neighborhoods just outside the city limits.

York County Growth

York County continued to experience steady growth during the 1970's and 1980's. The population grew 25% from 1970 to 1980. By 1990 it had expanded another 24% to almost 132,000. Based on 1995 estimates the population will increase at least 26% to 166,320.

Although the county is experiencing steady growth, it is currently fairly spread out. The higher concentrations of population are clearly in the eastern portion, around Rock Hill, Fort Mill and Tega Cay. Very little of the county is currently of urban density. In fact, only relatively small areas have more than one or two homes per acre. The following maps show the population and housing density changes from 1970 to 1995.

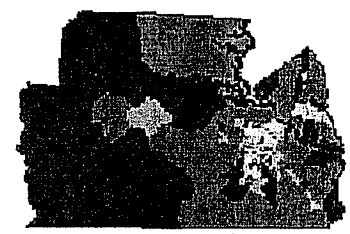
well below one unit per acre and development will be relatively widely spaced.



1970

[Red shows more than two housing units per acre, orange 1-2 units per acre, light greens are 1-5 acres per home, olive and darker green more than 10 acres per home]

Initially residents like the wide-open spaces of the rural development. Later, when the additional subdivisions begin to infill, the residents will decry the lack of infrastructure, especially in the area of transportation. Because of the strong relationship between transportation and land use, the Rock Hill Comprehensive Plan needs to relate to the local transportation planning area, RFATS.

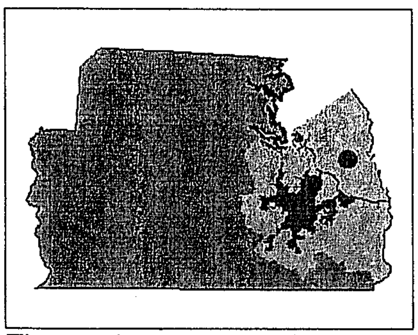


1980

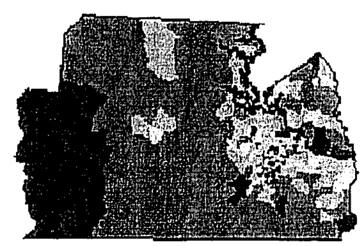
The Rock Hill-Fort Mill Urban Area

Rock Hill is located in the transportation planning area known as the Rock Hill-Fort Mill Area Transportation Study (RFATS) urban area. This is the area projected to be urbanized by the year 2015, and is shown against the York county profile. The area contains three municipalities: Rock Hill, Fort Mill and Tega Cay.

1995



This easternmost portion of York County represents 26% of the county land area, but since it is more urbanized (or densely populated) it has the majority of the county population. It too, has been experiencing the impact of regional growth.

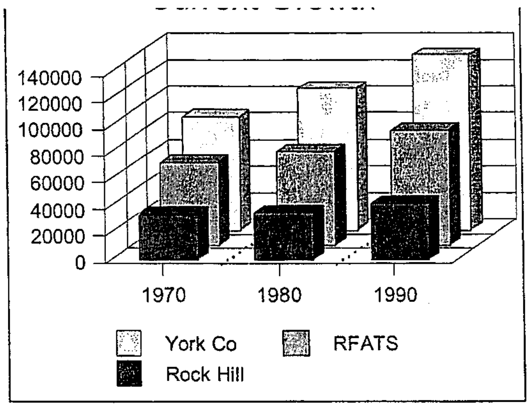


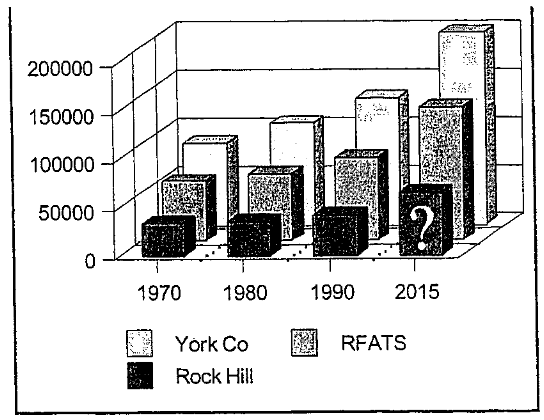
2015

In **1970**, over 72% of the people in York County lived in the RFATS urban area. The total county population was 85,326, and the population of the urban area was 61, 914. The population of Rock Hill at this time was 33,846 persons, or 54% of the urbanized area.

By **1980** the population in the county had grown to 106,270, and only 66% of the county lived in the urban area. (69,812). During this period the city grew to 35,344 by 1980, and represented 51% of the planning area.

By **1990** York County had grown to almost 132,000 and the urban area population of 86,000 again represented about 66% of the county total. The Rock Hill population of 41,610 in 1990 represented only 48% of the urban area population.





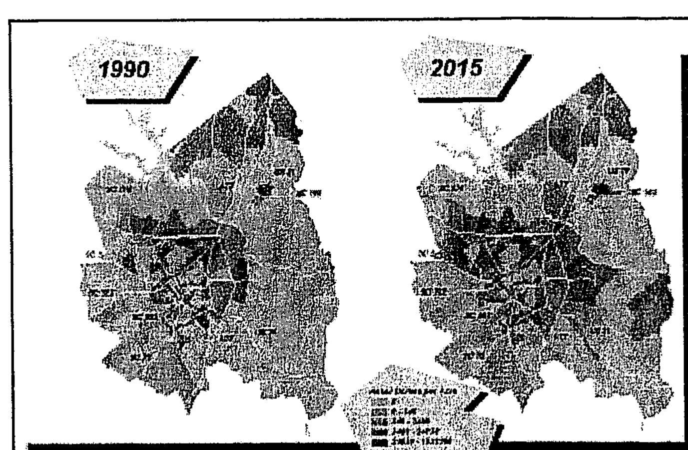
It is clear that the county has been growing slightly faster than the RFATS Urban Area, and the Urban Area (particularly the planning area outside the city) has been urbanizing slightly more rapidly than the city for the past two decades.

This is partly because of the growth on the northwestern side of Lake Wylie and the Clover school district area.

The urban area is expected to reverse that trend in the next two decades. Based on recent building rates, the area is attracting an increasing amount of the county's growth, for several reasons:

- The I-485 southern beltway has made commuting easier south of Charlotte and is directing increased investment in this direction;
- Regional Transportation Committees have supported both a metro mass transit connection to Rock Hill and a 20-mile "outer-outer" beltway along the Dave Lyle Corridor, connecting the ring cities;
- The Spring's Foundations proposed six "villages" surrounding Fort Mill will attract and absorb up to 25,000 new residents;
- The infrastructure availability in the I-77 corridor from Carowinds to Dave Lyle Boulevard has become increasingly attractive for residential development.

Projected 2015 demographics



The urban area statistics on the following pages are collected by Transportation Analysis Zones, or TAZ zones. The urban area has 251 TAZ zones, which are also census data collection zones, which are usually smaller than census block groups.

TAZ Zones are designed to capture population, journey to work data and other demographics that relate to traffic volumes and the use of the area street network. This information was collected as part of the 1990 census and will be updated as part of the 2000 census.

EXHIBIT 16

Map, Land Use Plan,
Fort Mill Planning Area, 1998

Land Use Plan
Fort Mill Planning Area

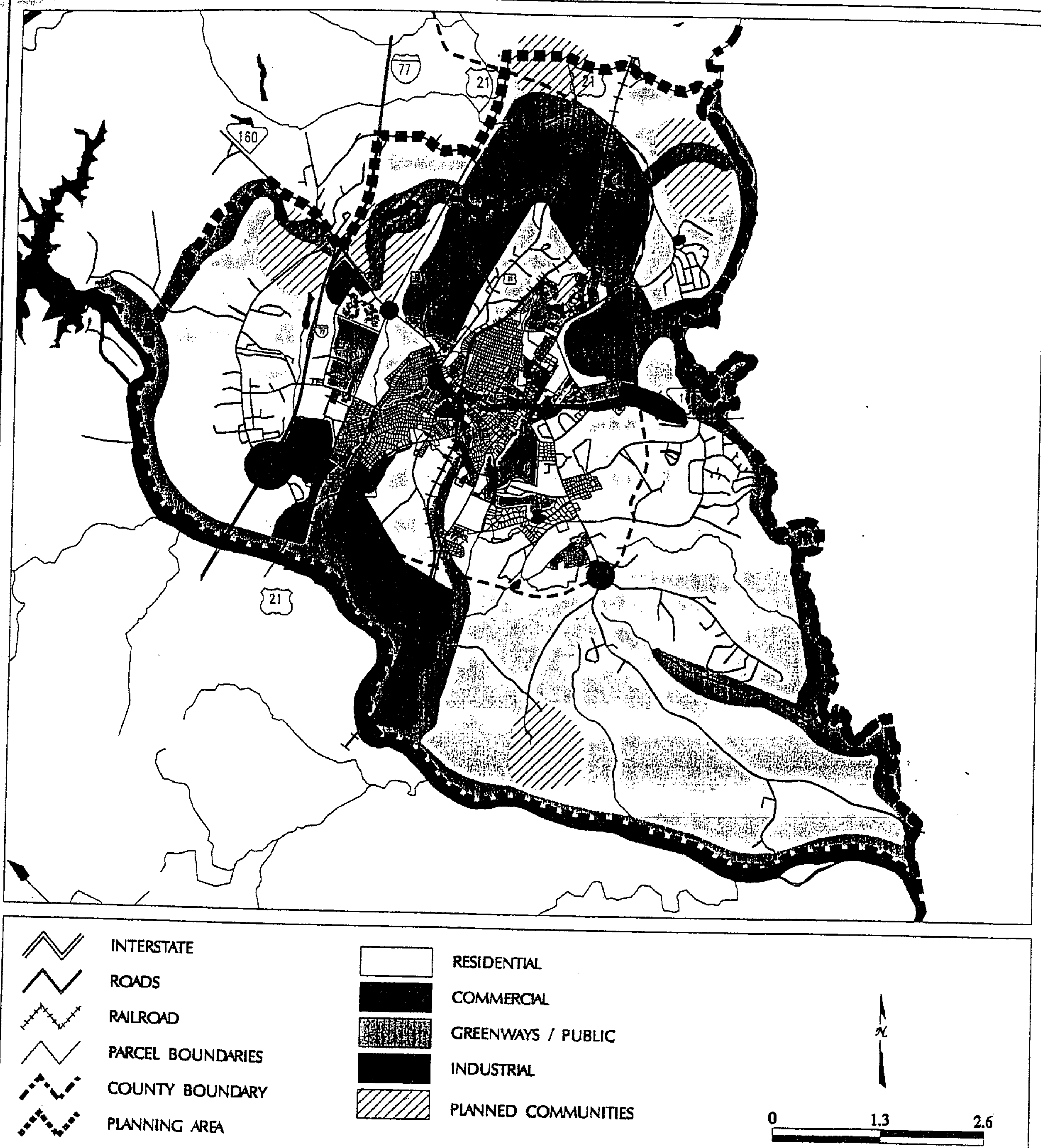


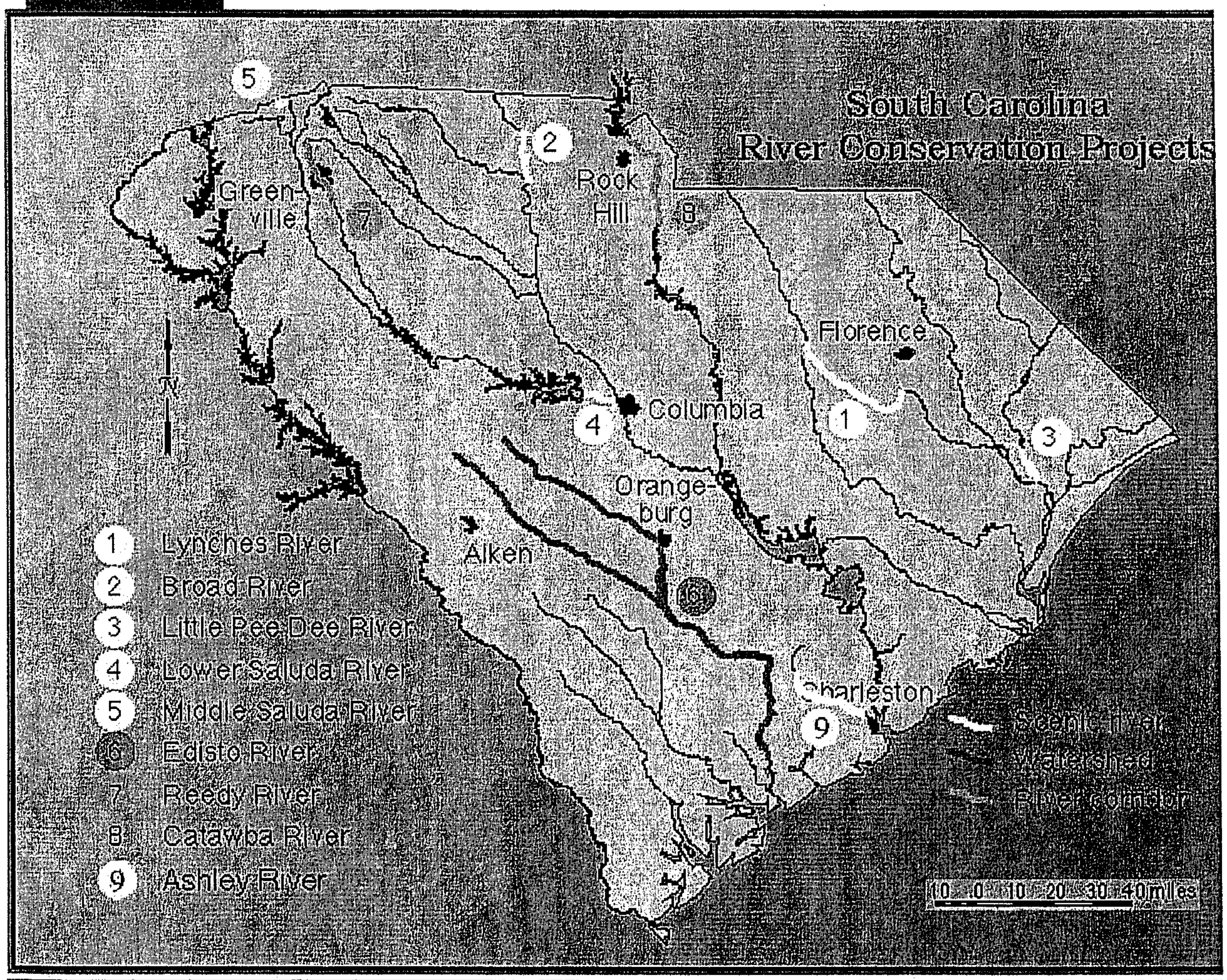
EXHIBIT 17

Map, South Carolina River Conservation Projects, Department of Natural Resources

Web Page, Catawba River Corridor Planning Project, Department of Natural Resources

The General Plan 2000-2010, A Comprehensive Plan for Rock Hill, South Carolina
Natural Resources pp. 1, LU-1, LU-3, 18, 20

South Carolina
River Conservation Projects



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SCDNR Home Page

Catawba River Corridor Planning Project

- Map
- Project Overview
- Study Process
- Contacts

Project Overview

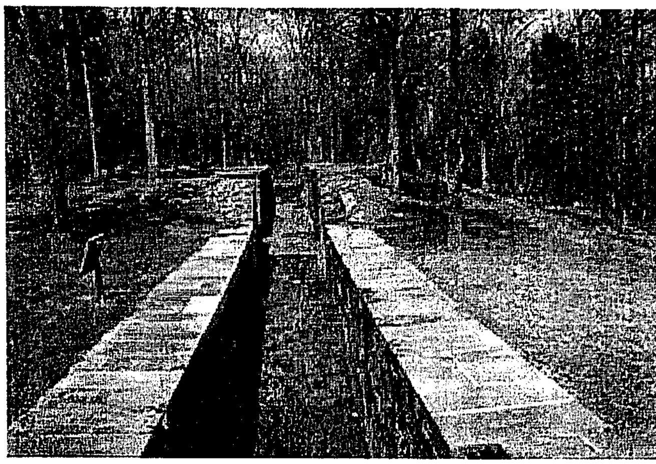
The Catawba River originates in the mountains of North Carolina and flows through a series of lakes and unimpounded stretches for over 200 miles until it meets Big Wateree Creek to form the Wateree River at Wateree Lake. The Catawba River Corridor Plan focuses on the 30-mile segment of the river below Lake Wylie dam to the S.C. Highway 9 bridge crossing near the upper reaches of Fishing Creek Reservoir.

The Catawba River enters South Carolina flowing through the Charlotte-Gastonia-Rock Hill Metropolitan Statistical Area which includes over 1.1 million people, according to the 1990 census. The three counties adjacent to this river segment, York, Lancaster and Chester, have a combined population of over 218,000 people. Also, the three-county area's population is projected to grow by at least 12 percent over the next ten years. Thus, the Catawba is well-situated to offer its unique diversity of natural, cultural and recreational resources to a large and growing population.

Study Process

The Catawba River Corridor Planning process was initiated in 1992 by the SC DNR in cooperation with the SC Department of Parks, Recreation and Tourism and the Catawba Regional Planning Council. The goal of this planning process was to create a vision for the Catawba River and its adjacent lands, to manage future growth in a manner that will protect the natural beauty, unspoiled character, and significant features that shape the Catawba River today. This planning process was citizen-based, to ensure that the resulting plan was wholly produced by members of the community in which it will be implemented.

The Catawba River Task Force was assembled, composed of people with the resources, expertise, and interest to provide a comprehensive overview of the river and the commitment to implement a final corridor plan developed by community members. Task force members include local government officials, landowners, and representatives of conservation organizations, industries, other local groups, and state agencies. Committees were formed for each of 15 critical issues facing the river corridor, as identified by the task force. Each committee developed a set of policy recommendations and presented them to the task force for discussion and approval.



A summary of the planning process and the resulting set of policy recommendations is provided in The Catawba River Corridor Plan, produced in 1994. While this report represents the completion of the planning process, it also marks the beginning of a new phase of the project: implementation. An implementation committee was established to take the lead in the implementation of the recommendations contained in the Corridor Plan. Comprised wholly of local citizens and decision makers from the Catawba region, this group remains very active in working on implementing recommendations.

Contacts

Catawba River Corridor Planning Project

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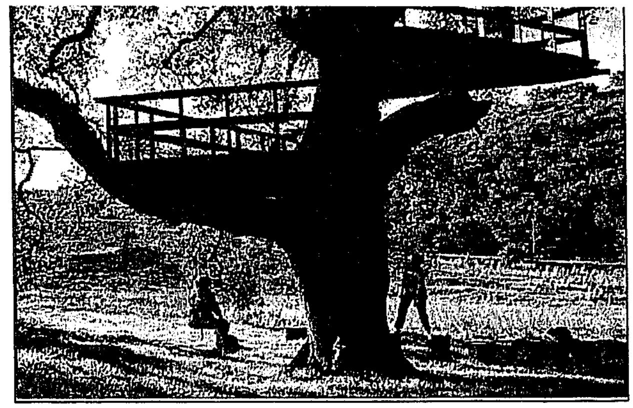
This document contains the following shortcuts:

Shortcut Text	Internet Address
Project Overview	http://water.dnr.state.sc.us/water/envaff/river/rivercor/catawba.html#over
Study Process	http://water.dnr.state.sc.us/water/envaff/river/rivercor/catawba.html#study
Contacts	http://water.dnr.state.sc.us/water/envaff/river/rivercor/catawba.html#contact
(e-mail: beasley@water.dnr.state.sc.us)	mailto:beasley@water.dnr.state.sc.us

THE GENERAL PLAN
2000-2010
A Comprehensive Plan for Rock Hill, South Carolina

Population
Community Facilities
Economic Conditions
Housing
Natural Resources
Cultural Resources
Land Use



Introduction

The Greater Rock Hill area is full of natural resources that are often taken for granted. The Catawba River, flowing streams and creeks, a large lake used for generating power and recreational purposes, heritage trees and a wide variety of animal and plant life are just a few of the resources we enjoy. These and other physical and natural characteristics contribute to the quality of life in the planning area.

These same natural resources have attracted steadily increasing growth and development for the area. While economic prosperity is one key to our community's future, growing according to our values is critical to our quality of life. We must plan carefully for future development to avoid sprawl and remain a livable community. To maintain a livable community it is important that we recognize and acknowledge the constraints and capabilities of our land with respect to absorbing growth and still sustaining and protecting both our natural resources and our quality of life.

The following topics are covered under the Natural Resources Element of the Rock Hill Comprehensive Plan:

- Geography and Location
- Topography and Hydrology
- Catawba River Basin
- Water Quality Data
- Air Quality Data
- Climate
- Soils
- Slope Characteristics
- Prime Agricultural and Forest Lands
- Plant and Animal Habitat
- Flood Hazard
- Parks, Trails, and Greenways
- Other Major Plans, Studies, or Initiatives
- Needs Assessment

INTRODUCTION

The Land Use Element of the 2010 York County Comprehensive Plan consists of a land use maps for each of the six (6) planning sectors as well as an inventory, needs assessment and goals and strategies. The land use maps designate the land use desired and encouraged by the York County Council, York County Planning Commission and the York County Planning and Development Services Department for the next ten (10) years. Land use designations have been applied to the entire jurisdiction of York County Government, with the exception of the incorporated areas. The previous plan elements as well as this element's inventory and needs assessment provide background and reasoning for the land use designations of each planning sector. This element also provides goals and strategies for the direction and future of the physical development of York County.

INVENTORY & ANALYSIS

Fort Mill Planning Sector

The Fort Mill planning sector encompasses the area within the Fort Mill Township, a State of South Carolina official area designation. Land use in this sector is influenced by a variety of factors, the most considerable being the presence of US Interstate 77. The I-77 corridor has had a significant impact since its construction in 1973, with land uses through this corridor tending to be more residential in character until the adoption of comprehensive zoning in 1986. The result of US Interstate 77, combined with the proximity of Charlotte, has been phenomenal growth in population.

Since then, and through the present, land uses have transitioned to predominantly light industrial and commercial. The land use pattern within the corridor also includes a variety of other uses including; Carrowinds theme park, the Knights Castle baseball stadium, the Baxter Traditional Neighborhood Development, and the Riverview residential development. The several municipalities within this sector also influence land use.

Fort Mill is the largest municipality, containing a well-established historic commercial center. Fort Mill has historically provided local employment and residential opportunities. However, as Fort Mill has reached development capacity, municipal limits are now expanding along all arterial roads. Tega Cay is a resort community with two golf courses and substantial frontage on Lake Wylie. Since the municipality's establishment in1982, the City has worked towards establishing itself as a fully functioning municipality and is currently preparing for a five (5) lane expansion of Gold Hill road and a proposed southern access road. These transportation improvements as well as the control of water and sewer facilities which service the area are significant factors which will influence land use in the surrounding area.

Land use within the Fort Mill planning sector will also be affected by regional influences. Fort Mill's metropolitan neighbor to the north, Charlotte, North Carolina, is a city offering world-class opportunities and experiences. The Geography of Fort Mill is such that it provides the nearest developable land to the Charlotte CDB outside of Mecklenburg County. This factor supports the Fort Mill effort to attract corporate offices. To date, this effort has been the most successful in the Metrolina region.

Fort Mill's proximity to the Charlotte-Douglas International airport also has a significant impact on land use. This international airport facility is connected to Fort Mill by two major roads; SC Hwy. 160 and I-77. The airport receives over five hundred (500) flights each day (Charlotte-Douglas Airport Welcome Center). These flights allow for convenient national and international travel for business executives. Flights handle cargo in the form of components and other value-added products important to our industries. The proximity of the airport will continue to attract people and industry to the Fort Mill area and York County. These factors will help to add corporate offices to the land use mix currently established and allow for people who work in the airline industry or the Westinghouse/Arrowood complexes to enjoy the proximity of Fort Mill and create demand for a wider-variety of residential and commercial land uses.

Infrastructure has also had a significant impact on land use for the Fort Mill area. Only recently has adequate infrastructure become available in this area. Inadequate infrastructure had encouraged only the slow growth of residential development, with little or no commercial or industrial presence. Trunk lines for both water and sewer have recently been installed to serve the Fort Mill planning sector. New capacity will encourage development of higher density residential, commercial and industrial land uses in the near future.

Another major regional influence is the presence of the Pineville retail attraction. Pineville hosts the largest commercial square footage available within close proximity to the Fort Mill sector. Restaurants, goods and services offered in Pineville have outpaced Rock Hill markets, further encouraging the Fort Mill growth. Pineville and Fort Mill have followed a typical pattern of land use development, commonly referred to as suburban sprawl.

This area's land use is also affected by a number of physiological features. Lake Wylie provides a recreational and scenic amenity as well as a water supply reservoir. This recreational amenity increases the value of homes and encourages the development of high quality residential property. Such development has resulted in the development of Tega Cay, a resort community, and other residential areas. This residential development has encouraged the location of commercial retail and service business to serve local residents and will continue to attract development over the next ten (10) years.

The Catawba River and Sugar Creek are significant influences on Fort Mill area land use. The Fort Mill planning sector contains one of the few lengthy sections along the Catawba suitable for recreation and wildlife. This amenity encourages high quality residential to locate within the area and provides for the disposal of wastewater and as well as a fresh water supply for industrial uses. Sugar Creek forms the eastern boundary of the planning sector. This degraded stream flows from Charlotte and is a major resource for the disposal of waste water for the Charlotte and Fort Mill areas. This major tributary to the Catawba also allows for flood abatement and, along with its tributaries, provides for another recreational and scenic natural corridor. Sugar Creek accommodates industrial land uses as well as encouraging residential and commercial development.

An important natural feature in the Fort Mill planning sector is the Anne Springs Close Greenway. This 2000 acre natural area is located between the Town of Fort Mill and the City of Charlotte. The natural area is a major outdoor attraction and an important recreational amenity to the Fort Mill area. The greenway defines the northern boundary of Fort Mill and serves as the core for the establishment of a system of open spaces within the sector. Such a central natural system will allow extensive development of trails and help interconnect the residential and commercial areas of the sector to amenities and other destinations.

Rock Hill East Planning Sector

The Rock Hill East planning sector encompasses the area east of the City of Rock Hill, both south and west of the Catawba river, and north of the Chester County border. Land use within the sector is influenced by growth associated with the City of Rock Hill, the presence of U.S. Interstate 77, the developing Catawba Indian Nation and the Catawba River.

The land use in this planning sector was historically rural, but is currently transitioning from agricultural to residential. Aside from the City of Rock Hill and the Catawba Indian Nation, three well-established communities, Leslie, Harmony and Catawba, are located along U.S. Hwy 21 and the CSX railroad line. The remainder of the residential development has been suburban in character. The transition to subdivision development in this sector has been very noticeable. Land once considered agricultural or vacant is now rapidly being consumed by subdivisions. Most of the subdivision development utilizes the RUD, Rural Development, designation, which is typified by 1-3 acre lots.

Major employment centers in this sector include Celanese-Acetate Corporation, AMP Incorporated, State Farm Insurance, and Bowater Incorporated. More recent developments include the Waterford Business Park, and the Galleria Mall area/complex. With the recent expansion of water and sewer services to the sector, opportunities have expanded for industry to locate along the I-77 corridor. The SC Hwy. 161 and U.S. Interstate 77 intersection improvements will make more acreage available for commercial use, similar to the Home Depot development along Cherry Road, just east of U.S. Interstate 77. Cherry Road west of U.S. Interstate 77 is also expected to continue to experience commercial development. In addition, continued industrial development is expected to occur along the SC Hwy. 161 extension.

The Catawba River has been a major area for concentration of planning efforts. Implementation of a Catawba River Corridor Plan (1994) is an example of current efforts. The River Corridor Plan has been a success and is ongoing. However, this Plan should be evaluated and updated regarding the accomplishments achieved to date. The most significant accomplishment has been establishment of the Catawba River buffer.

With regards to traffic, SC Hwy. 161 and U.S. Interstate 77 intersection improvements will result in a much more efficient traffic flow for the Celanese Road, Cherry Road and U.S. Interstate 77

NORTHSIDE GREENWAY is a .6 mile long asphalt trail located on 3.47 acres along Dave Lyle Blvd. The Trail begins at Northside Center and follows Manchester Creek to TechPark where it connects to the .9 mile long LAKESHORE TRAIL which loops around a small lake, crosses a the creek and rejoins the Northside Trail at the lake dam. Special features of both trails are the 4 pedestrian bridges over the waterways.

OAKWOOD ACRES PARK is located on 10 acres of flat land on Montclair Avenue. Facilities consist of a swimming pool and bathhouse, playground, 2 youth baseball/softball fields, basketball court, handball court, picnic shelter, and 2 sand volleyball courts.

RIVER PARK is an environmentally sensitive woodland area on 70 acres along the Catawba River that is accessed from Red River Road. River Park includes approximately 2 miles of scenic trails, with the River Trail being handicapped accessible. The beginning portion of this trail is covered with recycled tires, which makes it uniquely accommodating for visitors with special needs. Other trails and boardwalks wander throughout the park and wetlands area. Indigenous trees and plant material are marked throughout the trail system. A canoe launch provides for quick and easy access to the Catawba River. A picnic and animal observation area is located adjacent to the River. Future plans include a primitive camping area, interpretive center, and covered shelters.

SOUTHLAND PARK is located on 6.7 acres at Pearson and Winchester Streets. Facilities consist of a playground, softball field, basketball court, and a picnic shelter. This area is significant in that it is located near the Dept. of Natural Resources Blackjack Prairie Heritage Preserve on Blackmon Road.

SPENCER PARK is located on 9.8 hilly acres on Eastwood Drive. The Park is a linear green space with a creek running through the property. Facilities consist of a playground, basketball court, and picnic shelter.

WINTHROP PARK is located on 5 acres of flat land between Cherry Road and Eden Terrace. Facilities consist of a youth baseball/softball field, youth football field, playground, 2 tennis courts, basketball court, and picnic shelter. The Park is leased from Winthrop University and is part of a larger undeveloped area. In 1999, the City secured a Recreation Land Trust Grant in the amount of $17,250.00 toward purchase of the tract. Negotiations are currently pending.

WORKMAN STREET PARK is located on 4.8 acres of flat terrain on Workman Street. Facilities consist of a basketball court, play field, and picnic tables. The playground area has been fenced and turned over to the Rock Hill Public Housing Authority.

Map 9: Existing and Proposed Trails

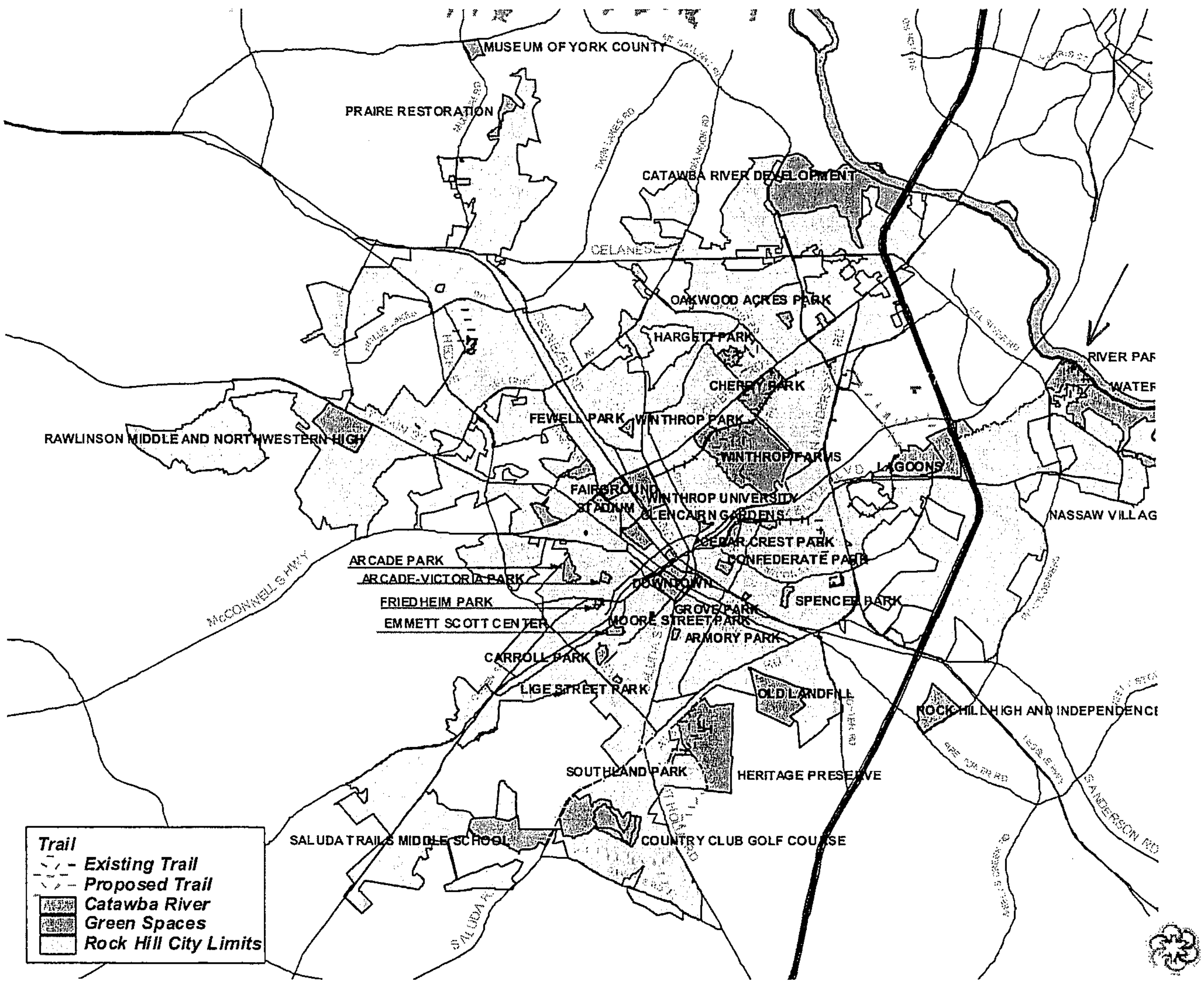


EXHIBIT 18

California Energy Commission, Siting Office, Preliminary Staff Assessment, East Altamont Energy Center, pp. 5.0-13 and 5.3-11

Controlled On Site Urea to Ammonia Generation Process (U_2A^{TM})
EC & C Technologies

Scorecard, Major Pollutants in York County the applicant's request of 50 cold starts and 250 hot start, 5100 hours steady state operation with duct burners, and the rest (3085 hours) steady state operation without the use of duct burners.

INITIAL COMMISSIONING

The initial commissioning refers to a period of approximately 60 days prior to beginning commercial operation when the combustion turbines will undergo initial test firing. During this commissioning phase, the project may operate at a low-load for a long period of time for fine-tuning. The District typically requires that each activity of the commissioning period be planned carefully, and that all NO_x and CO emissions and the time of commissioning be optimized to lessen the emissions from the turbines, duct burners and HRSG. It should also be noted that the NO_x and CO emissions during the commissioning period are not higher than emissions during normal start up of the facility; therefore, staff expects no new impact of the emissions during the commissioning period. All criteria air contaminant emissions during the commissioning period will be counted toward the annual emission limits; thus there is an incentive for the applicant to limit the commissioning period to the shortest time possible.

CLOSURE

Eventually the facility will close, either as a result of the end of its useful life, or through some unexpected situation, such as a natural disaster or catastrophic facility breakdown. When the facility closes, then all sources of air emissions will cease and thus all impacts associated with those emissions will no longer occur. The only other expected emissions will be fugitive particulate emissions from the dismantling activities. These activities will be short term and will create fugitive dust emissions levels much lower than those created during the construction of the project. Nevertheless, staff recommends that a facility closure plan be submitted to the Energy Commission Compliance Project Manager to demonstrate compliance with applicable District Rules and Regulations during closure activities.

AMMONIA EMISSIONS

Due to the large combustion turbines used in this project and the need to control NO_x emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia will mix with the flue gases to reduce NO_x; a portion of the ammonia will pass through the SCR and will be emitted unaltered, out of the stacks. These ammonia emissions are known as ammonia slip. The applicant has committed to an ammonia slip no greater than 10 ppm (Calpine, 2001a). On a daily basis, a 10 ppm slip is equivalent to approximately 2,500 pounds of ammonia emitted into the atmosphere from the East Altamont Energy Center facility.

IMPACTS

Air dispersion models provide a means of predicting the location and magnitude of the air contaminant impacts of a new emissions source at ground level. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions. The model results are often described as a unit of mass per volume of air, such as micrograms per cubic meter of explosion and fire resulting from sparks generated from heavy equipment rupture of the pipeline if the DOT proposal for a pipeline risk management plan becomes regulation. This worst case scenario would not result in significant asphyxiation hazard since natural gas disperses to the atmosphere rapidly when released. The worst case scenario is primarily a safety hazard to construction workers and nearby residences. The project owner will mark the pipeline in conformance with State and Federal regulations to lower the probability the above scenario.

The following safety features will be incorporated into the design and operation of the natural gas pipeline (as required by current federal and state codes): (1) while the pipeline will be designed, constructed, and tested to carry natural gas at a certain pressure, the working pressure will be less than the design pressure; (2) butt welds will be X-rayed and the pipeline will be tested with water prior to the introduction of natural gas into the line; (3) the pipeline will be surveyed for leakage annually (4) the pipeline will be marked to prevent rupture by heavy equipment excavating in the area; and (5) valves at the meter will be installed to isolate the line if a leak occurs. (See Conditions of Certification **HAZ-7**, **8**, **9**, & **10**)

Anhydrous Ammonia

Based on the discussion above, anhydrous ammonia and natural gas are the only hazardous materials that may pose a risk of off-site impacts. Anhydrous ammonia will be used in controlling the emission of oxides of nitrogen (NO_x) from the combustion of natural gas in the facility. The accidental release of anhydrous ammonia without proper mitigation can result in very large down-wind concentrations of ammonia gas. Two pressure vessel tanks will be used to store the anhydrous ammonia with a maximum of 10,200 gallons in each. Aqueous ammonia is less likely to cause high down-wind concentrations of ammonia and is generally the preferred form of ammonia to use in populated areas as it minimizes the toxic hazard.

The use of anhydrous ammonia can result in the formation and release of a cloud in the event of a release even without interaction with other chemicals. This is a result of its relatively high vapor pressure and the large amounts of anhydrous ammonia which will be used and stored on-site. Anhydrous ammonia is a gas at ambient temperature and therefore is stored under pressure. The rupture of a pipe, tank, or valve would result in a gas jet of ammonia leaving the containment structure at a high rate. The resultant cooling due to adiabatic expansion will have the effect of lowering the temperature of the containment vessel. However, pursuant to EPA and CAL ARP guidelines, the worst-case off-site consequence analysis did not consider this effect and instead assessed a catastrophic release of the entire contents of the tank.

To assess the potential impacts associated with an accidental release of ammonia, staff typically evaluates where four "bench mark" exposure levels of ammonia gas occur off-site. These include: 1) the lowest concentration posing a risk of lethality, 2,000 PPM; 2) the Immediately Dangerous to Life and Health (IDLH) level of 300 PPM; 3) the Emergency Response Planning Guideline (ERPG) level 2 of 200 PPM, which is also the RMP level 1 criterion used by EPA and California; and 4) the level considered by the Energy Commission staff to be without serious adverse effects on the public for a one-time exposure of 75ppm. (A detailed discussion of the exposure criteria considered by

Controlled On-Site Urea-to-Ammonia Generation Process (U_2A^{TM})

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The U_2A^{TM} Urea-to-Ammonia Generation Process (patent allowed) is a process developed by EC&C Technologies for use with SCR and SNCR systems. In the process, urea is dissolved into water and injected into a heated in-line reactor at a controlled rate and under conditions to provide a controlled rate of ammonia generation. The process produces a gaseous mixture of ammonia, carbon dioxide and water vapor, which are fed and mixed into the combustion gas stream for use as the reductant in controlling NOx emissions.

The U2A process provides the controlled release of ammonia by thermal hydrolysis of urea according to the overall reaction which includes the intermediate partial hydrolysis of urea to carbamate:

$$NH_2CONH_2 + x\,H_2O \leftrightarrow NH_2CO_2NH_4 \rightarrow 2\,NH_3 + CO_2 + (x-1)\,H_2O$$

The overall reaction is endothermic and requires heat input. The rate of the reaction is a strong function of temperature. The reaction kinetics are well understood and were quantified during EPA sponsored SBIR Phase I and II development.

The reactor feed is a solution of approximately 40 to 50% urea in deionized water. At the operating conditions of the reactor the solution approaches equilbrium with respect to the ammonia, ammonium carbamate, dissolved CO2, and urea composition of the reactor liquid.

The hydrolysis reactor operates at elevated temperature and pressure. Operating pressure is maintained in the reactor at a level such that the solution is always maintained below its "boiling" point. Using indirect heat exchange the hydrolysis reactor maintains a closed material balance which provides for straightforward control of ammonia generation based on the temperature of the reactor.

As both ammonia and CO2 are much more volatile than water, the reactor liquid becomes water rich and the ammonia content of the reactor liquid in equilibrium with the vapors is in the range of 2-3%. This limits the total amount of ammonia inventory in the system. The gases are maintained at pressure in the reactor vessel allowing for easily controlled release of ammonia vapors to the process.

The gases leaving the reactor contain only ammonia, carbon dioxide, and water and are further diluted with heated air as a carrier gas such that the ammonia content of the mixture is less than 5% by weight. The resulting gas is maintained at a temperature to avoid water condensation and is delivered to the ammonia injection grid system for the SCR process. For SCR and SNCR systems, NOx reduction results are equivalent to those obtainable with anhydrous or aqueous ammonia.

Utilities, SCR providers and engineering firms have been strongly receptive to this new process which offers the advantage that no storage, shipping, or handling of toxic ammonia solutions is required

Hamon Research-Cottrell and Wahlco Air Systems are exclusive co-licensees of the process. It first commercial demonstration on an existing combined cycle SCR at a New England utility site is expected to be operational in July 2000 to provide confirmation of the work that has already been completed under EPA sponsored grants.

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ENVIRONMENTAL DEFENSE
finding the ways that work

Your Zip Code: 29715
Your Community: YORK County

What Are the Major Pollutants?
Reported Environmental Releases from TRI Sources in 1999

Rank	Chemical Name	Pounds
1	METHANOL	1,126,024
2	ETHYLENE GLYCOL	417,629
3	AMMONIA	196,233
4	CHLOROFORM	174,740
5	XYLENE (MIXED ISOMERS)	165,356
6	N-HEXANE	158,146
7	ZINC COMPOUNDS	136,841
8	METHYL ETHYL KETONE	130,435
9	MANGANESE COMPOUNDS	117,785
10	DICHLOROMETHANE	109,446
11	ACETALDEHYDE	92,263
12	BARIUM COMPOUNDS	91,549
13	TOLUENE	84,103
14	FORMALDEHYDE	67,470
15	SULFURIC ACID	65,813
16	PHENOL	64,432
17	CRESOL (MIXED ISOMERS)	50,191
18	ACETONITRILE	29,367
19	HYDROCHLORIC ACID	26,381
20	HYDROGEN CYANIDE	17,505

EXHIBIT 19

Article, Fort Mill Times, "CALPINE: Calpine, county cut strike deal"
March 1, 2002

Article, Fort Mill Times, "State Legislators Question Gas Tax Fund"
February 22, 2002

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CALPINE: Calpine, county cut strike deal

By Patricia Larson The Fort Mill Times

(Published March 1, 2002) - FORT MILL TOWNSHIP-Calpine Corp. will get several tax cuts to build its plant in Bradley Industrial Park, but the taxes the company will pay still have county officials smiling broadly.

Calpine's $400 million investment qualifies for several special tax cuts because it's so big. The state is also offering breaks because Calpine has two other plants in the state, with all three investments totaling over $1 billion.

Th county has negotiated a "fee-in-lieu-of-tax" agreement with Calpine. In this popular economic incentive, Calpine will pay a flat annual fee instead of property taxes on their equipment and machinery-most of the project. They will pay 5 percent on their equipment, valued at $378.5 million. The usual tax rate on equipment is 10.5 percent, but few companies pay that-especially when they invest as much as Calpine.

The county will get about $2.2 million a year for 20 years after the plant opens in 2005-including $1.7 million for the school district. That $1.7 million would about double all other fee-in-lieu-of-tax money the school district gets now, says Superintendent TEC Dowling.

Calpine officials wouldn't say how much the deal would save them on property taxes.

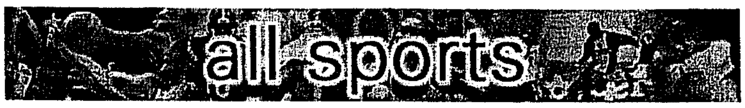
Fee-in-lieu-of-tax deals are common-Fort Mill Township already has seven-but only two have rates locked in for 20 years. Calpine's fee, while locked in, is at a higher tax rate than normal, county leaders say, and won't go down as the plant depreciates.

Calpine qualified for a "super fee" of 4 percent, but the county refused, says County Council Chairman Mike Short.

"They wanted 4 percent, we asked for 6 percent, and we settled on 5 percent," Short said.

Commerce officials have also offered perks: a and move it off site.

Negotiations aren't over. They have two years to work out the deal, and the County Council must OK it.



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State legislators question gas-tax fund

By Patricia Larson The Fort Mill Times

(Published February 22, 2002) - FORT MILL TOWNSHIP-Some state legislators are criticizing how state gas taxes have been used to lure big business to South Carolina.

The state's $18 million incentive fund, which comes from a 16-cent gas tax, is designed to pay for road and infrastructure improvements that would then prompt industries to move into the state. It has played a role in many Fort Mill projects, including a failed 1999 deal that would have brought Microsoft here, as well as an ongoing plan for Calpine to build a power plant in Bradley Industrial Park.

But some legislators, led by state Reps. Annette Young (R-Summerville) and Becky Meacham-Richardson (R-Fort Mill), are criticizing how the incentive fund has been used.

"It was set up for infrastructure needs for new companies coming in," Young said. "They have not used it for that."

The Advisory Coordinating Council for Economic Development oversees the money. It is chaired by Commerce Secretary Charles Way, an appointee of Democratic Gov. Jim Hodges.

Young began asking questions last year, when as chair of the subcommittee that keeps an eye on the Coordinating Council, she requested a report from Way on the fund.

"In that report, I saw a lot of bad decisions in my opinion," Young said. "There were quite a few things."

Among them, money for improvements to golf courses in Horry County and Charleston, land purchases, a cemetery in Oconee County, and technology training programs at the University of South Carolina.

Young attempted last week to take away the incentive fund from the Department of Commerce, giving the Department of how the money's used. The bill is still moving through the House.

"The money should be used for economic development," Young said. "It's not excusable."

Way was out of town and not available for comment before press time Tuesday.

The Microsoft deal

One of the spending projects Young and Meacham-Richardson question is $4 million for two technology training programs at the University of South Carolina-money designed to help lure Microsoft to Fort Mill in 1999.

It included $1.5 million to the USC Foundation's private company NetGen for professional development centers at schools including York Technical College. It also included $2.5 million to pay for information technology programs at USC.

The Coordinating Council gave USC the money about the time Commerce officials were courting Microsoft, which was thinking of moving its product support headquarters from Charlotte to Fort Mill. The two programs were designed to offer professional certification in Microsoft software.

Microsoft later decided to stay in Charlotte, but USC still received the $4 million.

That's a surprise to York County officials who were involved with the Microsoft negotiations. County Council Chairman Mike Short and county Economic Development Director Mark Farris said they weren't aware the programs were actually set up. They assumed since the Microsoft deal fell through, so did the $4 million.

But they both added that the USC funds are not something the county would have had control over, since the incentive fund is state tax money. "There were no promises made on behalf of York County," he added.

USC is still using the money, but York Tech is no longer involved. York Tech spokesman Joe Polinski said their partnership with NetGen ended two years ago. Now they partner with a Charlotte company to provide Microsoft

County $3 million from the incentive fund for the proposed Calpine plant.

The money will be used to upgrade a regional natural gas pipeline already planned by York County Natural Gas-widening and extending it 14 miles to the Calpine plant. The entire upgrade will actually cost about $20 million, but who will pay the difference hasn't been decided yet.

County officials say the upgrade will benefit the public-a requirement to use the incentive fund.

Early last summer Calpine approached Commerce about building a natural gas plant. Commerce officials began negotiating with Calpine about possible incentives, including using gas tax money.

Commerce officials then notified the county about Calpine's interest, and mentioned that incentive funds would be made available. County officials reminded Commerce the money needed to be used for infrastructure work only, and Bradley Industrial Park didn't need any improvements.

By November, county officials working with Calpine and York County Natural Gas put together a plan to use the money to upgrade the pipeline. Commerce officials agreed.

Between that time, the Commerce department came under fire from legislators after Commerce chief of staff Wayne Stirling unexpectedly resigned in September. A later investigation revealed misuse of some public funds, leading legislators to scrutinize the entire department including the incentive fund.

In November, Commerce sent a letter of recommendation to the county emphasizing that the $3 million be used for public infrastructure.